PB84-155175

Cogeneration: Status and Environmental Issues

TRW Energy Engineering Div., McLean, VA

Prepared for

Industrial Environmental Research Lab.
Cincinnati, OH

Feb 84

U.S. Department of Commerce
National Technical Information Service
NTIS

EPA-600/7-84-023
February 1984

PB84-155175

COGENERATION: STATUS AND ENVIRONMENTAL ISSUES

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Contract 68-03-2560

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TECHNICAL REPORT DATA (Please read Instructions on the reverse before completing)		
1. REPORT NO. EPA-600/7-84-023	2.	3. RECIPIENT'S ACCESSION NO. PB84 155175
4. TITLE AND SUBTITLE Cogeneration: Status and Environmental Issues		5. REPORT DATE February 1984 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) John Dadiani		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS TRW Energy Engineering Division 8301 Greensboro Drive McLean, Virginia 22102		10. PROGRAM ELEMENT NO. C2JN1E 11. CONTRACT/GRANT NO. 68-03-2560
12. SPONSORING AGENCY NAME AND ADDRESS Industrial Environmental Research Laboratory-Cin. Office of Research and Development U.S. Environmental Protection Agency Cincinnati, Ohio 45268		13. TYPE OF REPORT AND PERIOD COVERED Final 6/79 to 7/81 14. SPONSORING AGENCY CODE EPA/600/12-
15. SUPPLEMENTARY NOTES EPA Project Officer - Benjamin L. Blaney - 513/684-4363		

16. ABSTRACT

The purpose of this project was to determine the planned cogeneration development by the utility and industrial sectors; to assess the environmental impacts and energy savings from cogeneration; and, to identify potential environmental issues and regulations impacting cogeneration development. Major emphasis was placed on environmental impacts. The study investigated the energy savings and environmental impacts of five industrial facilities which are considering a switch to in-plant cogeneration. Potential regional environmental impacts of cogeneration development in New England, the Tennessee Valley Authority service area and northern New Jersey were also determined. Finally, the environmental impacts of a cogeneration-based district heating system were considered. It was found that there are a number of factors which determine the relative magnitude of environmental impacts of a cogeneration system compared to a conventional energy supply system. These include fuel type, control technology efficiency and the type of power source used. As a result, each cogeneration system must be considered separately. Generally, it was found that the most significant environmental impacts were changes in air emissions; these increased on-site, but usually were reduced on a region-wide basis.

17. KEY WORDS AND DOCUMENT ANALYSIS		
a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Cogeneration Energy Pollution Fuels Utilities	Environmental assessment Energy potential Stationary sources	
18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS (This Report) Unclassified	21. NO. OF PAGES 81
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

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FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollution impacts on our environment and even on our health often require that new and increasingly more efficient pollution reduction methods be used. The Industrial Environmental Research Laboratory - Cincinnati (IERL-Ci) assesses new and improved methodologies that will meet these needs both efficiently and economically.

This report describes the status of and environmental issues associated with the use of cogeneration. This report should be useful for evaluating the growth potential of cogeneration and the environmental impacts of such growth. It should be of value to researchers in the utility, energy, and environmental fields. Requests for further information concerning this technology should be directed to the Director, Energy Pollution Control Division, IERL-Ci.

David G. Stephen
Director
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Cincinnati

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ABSTRACT

This project determined the planned cogeneration development by the utility and industrial sectors; assessed the environmental impacts and energy savings from cogeneration; and, identified potential environmental issues and regulations impacting cogeneration development. Major emphasis was placed on environmental impacts.

The study investigated the energy savings and environmental impacts of five industrial facilities which are considering a switch to in-plant cogeneration. Potential regional environmental impacts of cogeneration development in New England, the Tennessee Valley Authority service area and northern New Jersey were also determined. Finally, the environmental impacts of a cogeneration-based district heating system were considered.

It was found that there are a number of factors which determine the relative magnitude of environmental impacts of a cogeneration system compared to a conventional energy supply system. These include fuel type, control technology efficiency, the type of power source used and the types of utility units displaced. As a result, each cogeneration system must be considered separately. Generally, it was found that the most significant environmental impacts were changes in air emissions; these increased on-site, but usually were reduced on a region-wide basis.

This report was submitted in fulfillment of Work Directive No. T5011 under Contract No. 68-03-2560 by TRW, Inc. under sponsorship of the U.S. Environmental Protection Agency. This report covers a period from June 1979 to July 1981.

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CONVERSION FACTORS AND ENERGY EQUIVALENTS OF FOSSIL FUELS

CONVERSION FACTORS

1 kW-hr (kWh)	=	3,413 Btu	=	3.60×10^6 Joules
1 MW-yr	=	2.992×10^{10} Btu	=	3.16×10^{13} Joules
1 lb steam/hr*	=	1,168 Btu/hr	=	342 watts

*Steam pressure 10.3 Megapascals (1500 psig)

ENERGY EQUIVALENTS

Petroleum	
Crude Oil	37.2×10^6 Joules/liter (5.60×10^6 Btu/BBL)
Residual Fuel Oil	41.8×10^4 Joules/liter (6.29×10^6 Btu/BBL)
Distillate Fuel Oil	38.7×10^6 Joules/liter (5.83×10^6 Btu/BBL)
Coal	
Anthracite	6.1×10^6 Joules/kilogram (25.4×10^6 Btu/ton)
Bituminous	6.3×10^6 Joules/kilogram (26.2×10^6 Btu/ton)
Natural Gas	
Dry	38.4×10^6 Joules/cubic meter (1,031 Btu/cubic ft)

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APPLICATION OF SI PREFIXES*

Multiplication Factor	Prefix	Symbol
10^{18}	exa	E
10^{15}	peta	P
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto	h
10^{1}	deka	da
10^{-1}	deci	d
10^{-2}	centi	c
10^{-3}	milli	m
10^{-6}	micro	u
10^{-9}	nano	n
10^{-12}	pico	p
10^{-15}	femto	f
10^{-18}	atto	a

*In this report a million British thermal units (Btu's) is designated by MM Btu.

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SECTION 1

INTRODUCTION

BACKGROUND

The conservation of existing energy resources is receiving great emphasis in this country as a result of decreasing energy supplies and high fuel costs. Conservation programs are encouraged since they can usually be implemented sooner than the developmental efforts required for obtaining new sources of energy supplies. Numerous conservation measures are being examined, with cogeneration attracting great attention for use in the utility, industrial, commercial and residential sectors. In simplest terms, cogeneration is the simultaneous production of electricity and useful thermal energy from a single source such as a power plant or industrial boiler. Cogeneration can be used in in-plant power production, industrial parks, and district heating systems. Although used for many decades in the United States and abroad, it accounts for only an estimated 4 percent of the national electricity production.

Interest in cogeneration has increased over the last several years as a result of the benefits of this technology. Overall efficiencies of as high as 85 percent have been described as compared with 30 to 35 percent for most conventional systems used in producing electricity. Benefits include overall reduced fuel consumption and often, reduced overall pollution emissions, increased energy efficiency, and economic benefits in capital and operating costs. Among the disadvantages are increased local pollution around the cogeneration plant site, and reliance on scarce fuels such as oil and gas for the small cogeneration systems utilizing diesels and gas turbines.

Several issues and potential constraints to developing cogeneration have been identified and need to be resolved before the technology can gain wide acceptance. Due to its growth potential over the next several years, the U.S. Environmental Protection Agency is charged with assuring that this and all other technologies are developed in an environmentally acceptable manner. The goal of this study is to identify the major environmental issues related to cogeneration which will need expansion of current research efforts or new research areas.

OBJECTIVES OF STUDY

In order to meet the stated goal of the study, the following objectives were developed:

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- To determine the potential for cogeneration development by the utility and industrial sectors.
- To assess the environmental impacts and energy savings from cogeneration.
- To identify potential environmental issues and regulations impacting cogeneration development.

Since there is currently a considerable amount of information available on the technical, economic, and institutional issues dealing with this technology, they will be only briefly discussed in this report with the major emphasis directed at environmental issues. The specific tasks performed for this study are summarized as follows:

Task 1 - Overview of Cogeneration

In this task, a review was made of recent assessments of cogeneration potential in selected industries and regions in the United States. In addition the types of combustion devices currently available and planned for cogeneration applications are described. Also presented are the constraints to the development of cogeneration systems.

Task 2 - Reference Case Analysis

Case studies of five specific plant sites were made to assess the environmental effects of installing cogeneration systems. The type of combustion device and fuel used were included in the analysis. In addition an environmental analysis of an industrial park cogeneration application was performed. Finally, the environmental impacts of cogeneration development in three regions of the United States were analyzed.

Task 3 - Expansion of Results

A methodology was developed that could be used to estimate the national energy savings and environmental pollution changes resulting from cogeneration.

Task 4 - Identification of Environmental Issues and Research Needs

The major environmental issues identified by current and potential users of cogeneration systems are presented as well as additional research needs. Included among these needs is an examination of environmental benefits and impacts of district heating systems due to the increased interest in these applications.

Task 5 - Conclusions and Recommendations

The results of the study and recommendations for additional research to assure that cogeneration is developed in an environmentally acceptable manner were compiled. The results are intended to be used by government and industrial personnel concerned with cogeneration development and regulation.

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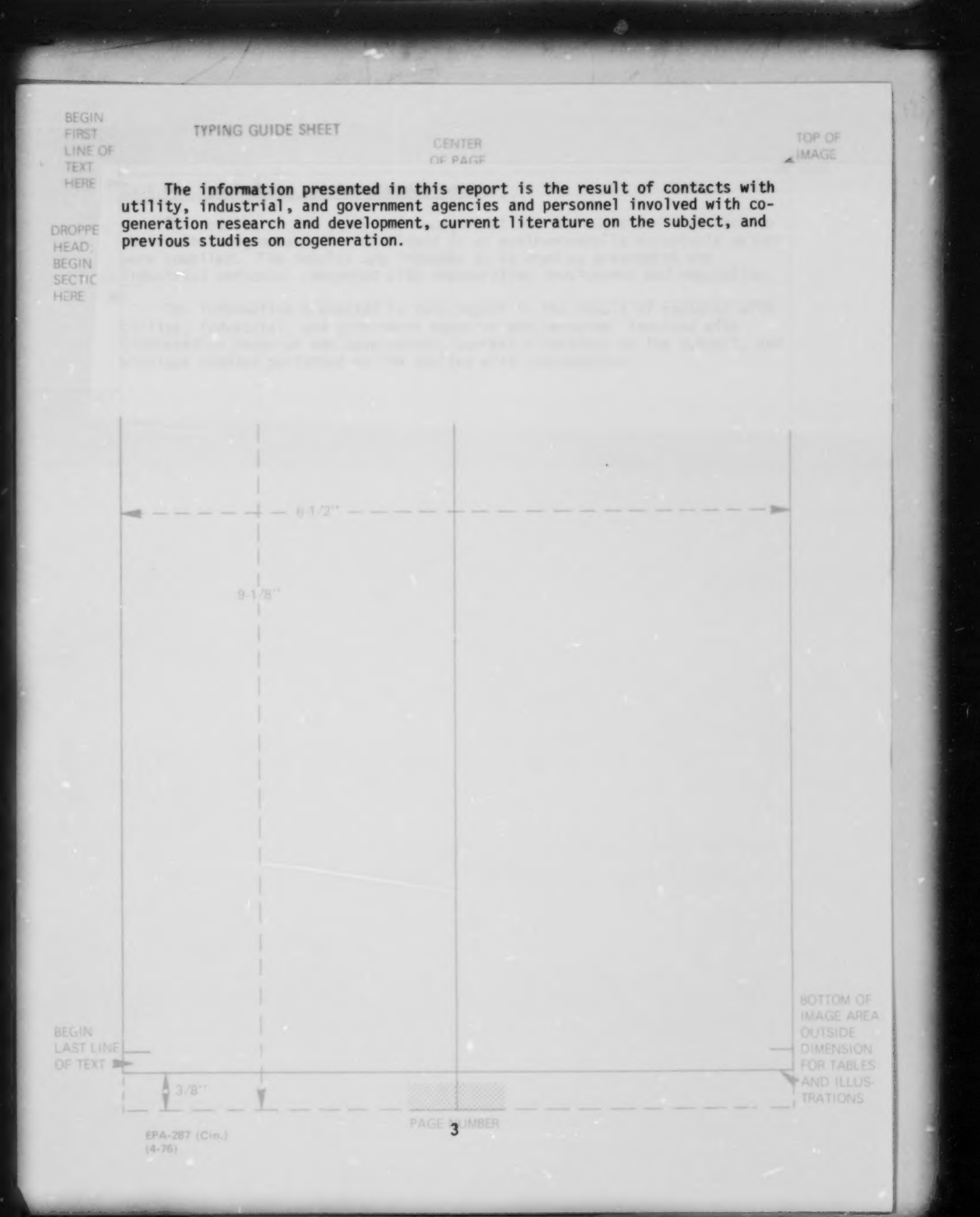

The information presented in this report is the result of contacts with utility, industrial, and government agencies and personnel involved with co-generation research and development, current literature on the subject, and previous studies on cogeneration.

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SECTION 2

SUMMARY

CONCLUSIONS

The use of cogeneration as a means of conserving energy has received increasing interest over the last several years due to its improved efficiency over conventional systems for generating electricity and thermal energy. Although the technology for implementing cogeneration is currently available, there are several constraints to its development. This section summarizes the potential energy savings and environmental issues applicable to cogeneration.

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Cogeneration Potential

Several studies have been conducted during the last five years to assess the fuel savings impacts of cogeneration.[1,2,3,4,5] The industrial sector has been examined in more detail in these studies as it is estimated to have the best near-term potential for utilizing cogeneration due to several factors. These factors are: the thermal energy demands of this sector are approximately 23 exajoules (22 quads) compared with 18 exajoules (17 quads) for the housing and commercial sectors; and much of the industrial thermal demand is concentrated in energy intensive industries with large plants making penetration of the industrial market a more feasible task. District heating systems also show promise for saving scarce fuels. However, the implementation of these systems is slower due to increased regulatory, institutional and economic constraints which may make it less attractive.

The predominant combustion devices currently used in cogeneration systems and which will continue into the near-term (1985), are steam turbines, gas turbines and diesel engines. Fluidized bed combustion may be available during this decade, and some emerging technologies which may be available in the far term (1995 to 2000) include fuel cells and Stirling engines.

A few utility companies in the U.S. (Gulf States Utilities Co., Texas and Public Service Electric and Gas Co. of New Jersey) have been cogenerating for decades. However, on a national scale, cogeneration accounts for only a small portion of electricity production. Several studies have been made to assess the cogeneration potential in selected regions of the U.S.[4,5] The interest of EPA in these assessments is to determine if the potential development of the technology is significant and to identify potential environmental impacts that need to be resolved. The estimated energy savings from cogeneration have ranged from 0.64 to 1.94 exajoules (0.60 to 1.83 quads) for 1985 depending upon which industries have been included in the estimates, and between 1.4 and 3.85 exajoules (1.33 and 3.65 quads) by 1990.[6]

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Much of the energy savings will be for residual oil, distillate oil, and natural gas, as these may be replaced by coal and process residuals. The industries in which the major energy savings are expected to occur are as follows: petroleum refining, chemicals, pulp and paper, food and textiles. Energy savings estimates have also been made on a regional basis since certain industries, types of fuels used, and regulatory and utility commissions vary from region to region. In the Tennessee Valley Authority service area, an estimated annual savings of 0.29 to 0.99 gigaliters (1.8 to 6.2 million barrels) of oil equivalent could be achieved in the 1989 to 1998 time period, with an aggressive program to increase cog neration operations. In the New England area, an estimated 0.61 gigaliters (3.85 million barrels) of oil per year can be saved in Massachusetts and 1.6 gigaliters (10.1 million barrels) per year in New England by the mid-1980's. The estimated energy savings for the three regions considered in this report are presented in Table 2-1.

TABLE 2-1. REGIONAL ENERGY SAVINGS POTENTIAL OF COGENERATION

Region	Potential Energy Savings or Increases Due to Cogeneration (Oil)	
	Gigaliters	Million Barrels
Tennessee Valley Authority	0.29 - 0.99	(1.8 - 6.2) Savings
New England	1.6	(10.1) Savings
Public Service of New Jersey	2.1	(13.0) Increase*

*Increase due to possible displacement of nuclear power stations.

Environmental Impact

The environmental impacts of cogeneration systems are dependent upon the type of combustion device used, the type of power plant displaced, the fuels used and displaced, and the existing environmental quality. Since current technologies for producing electricity and steam will be used in cogeneration applications in the near term, the environmental impacts will be similar to those associated with these technologies. The major impact will be from the increased fuel use by the cogeneration system, will be very site specific in nature rather than generic, and will need to be assessed for each individual cogeneration site.

The main environmental impact from cogeneration will be air pollution emissions due to increased fuel combustion on-site, with the greatest effects occurring from those systems located in urban areas. The increased efficiency of cogeneration allows a net reduction in overall fuel use which may result in decreased air pollution as well as other environmental residuals depending upon fuel use and displacements. Table 2-2 shows the various fuel use

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TABLE 2-2. ENERGY AND ENVIRONMENTAL BENEFITS OF COGENERATION FUEL USE OPTIONS

Planned Cogeneration System Fuel Use	Current Industrial Plant Fuel Use Replaced	Utility Fuel Saved	Remarks
Coal	Oil/Gas	Oil/Gas	Potential for on-site environmental impact; Best option for scarce fuels savings.
Coal	Oil/Gas	Coal/Nuclear	Potential for on-site environmental impact; Large gas/oil savings potential.
Coal	Coal	Oil/Gas	No major environmental impact; moderate oil/gas savings.
Oil/Gas	Oil/Gas	Oil/Gas	No major environmental impact; moderate savings of oil/gas.
Coal	Coal	Coal/Nuclear	Small local environmental impact; net regional environmental benefit; no oil/gas savings but net savings of coal.
Oil/Gas	Oil/Gas	Coal/Nuclear	Small local environmental impact; net regional environmental benefit; negative oil/gas savings
Oil/Gas	Coal	Oil/Gas	Environmental benefit; very negative oil/gas savings.
Oil/Gas	Coal	Coal/Nuclear	Best option from environmental standpoint; worst option for saving oil/gas.

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options for an industrial plant and the fuel that may be off-loaded at a utility, indicating that the options most consistent with national energy goals for reducing oil and gas use are not necessarily the most beneficial from an environmental basis.* However, the development of cogeneration systems is not expected to cause any major adverse environmental impacts because current state and Federal regulations require that appropriate emission control systems be used. On the other hand, these regulations may in some cases limit the extent to which cogeneration can be economically developed.

Several reference cases for cogeneration systems have been analyzed in this study to assess air, water, solid waste, and thermal pollution impacts. Industrial plants which are considering cogeneration were selected in each of five energy intensive industries: chemicals, textiles, food, petroleum refining and pulp and paper. The analysis indicated that on-site air pollution emissions would increase for each plant, with the reduction in utility emissions due to reduced fuel use off-setting cogeneration plant emissions in two cases. The increase in on-site emissions due to increased fuel use by the cogeneration plant over that which would be required solely for the production of electricity or heat can be a major environmental constraint to cogeneration. However, the total fuel use and subsequent emission levels would be lower for a cogeneration plant in comparison with two plants separately producing electricity and thermal energy. Water pollutants, solid wastes and thermal effluents would also be reduced from the in-plant systems. Cogeneration has significant impacts on reducing reject heat since much of this would be recovered rather than being released into the environment.

A similar case was analyzed for an industrial park configuration and resulted in significant decreases in regional pollution levels of suspended particulates, sulfur dioxide and thermal effluents. However, the on-site emissions were also significant, indicating that potential permitting problems could occur since there would be several large fuel combustion sources in a confined area as opposed to dispersed plants. The environmental effect of any industrial park is highly site specific and dependent upon the number and types of plants within the park, steam/heat demands, and types of fuels used by each of the industrial plants. Existing site specific environmental quality which is also a factor is influenced by other pollution sources in the area, by climatology and by physiography. The environmental impacts of one industrial park cannot easily be extrapolated to another industrial park for these reasons.

A district heating reference case was also examined in this study and also indicated that environmental benefits would result. The analysis indicated net reductions in suspended particulates, sulfur dioxide, and waste heat. These reductions are achieved from reduced fuel use in commercial and residential heating systems which do not have any emission controls and from applying stringent controls to the district heating plant. Water pollution and solid wastes increase as a result of the pollution control system and process requirements in the heating plants. There are virtually no releases of these pollutants from residential units.

*Since coal is potentially a dirtier fuel than oil or gas.

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As previously mentioned, cogeneration systems can be developed without producing major environmental impacts, although some site specific environmental protection requirements may pose some constraints. Additional issues which need to be considered are regulatory, institutional and economic in nature.

RECOMMENDATIONS

The study reported here identified several environmental issues associated with cogeneration development and made recommendations regarding what further research is needed should cogeneration, as we expect, have significant market penetration in the coming decade. The recommendations are in the following areas:

- Development of an environmental data base for cogeneration systems.
- Increased research in pollution controls for small combustion devices.

Environmental Data Base

The development of an environmental data base would provide up-to-date assessment of this expanding energy supply technique. Potential users of cogeneration systems could employ this information to assess potential impacts and regulatory policies that have to be considered when such systems are installed.

Pollution Control Research for Small Combustion Devices

Due to uncertainties associated with future supplies of oil and gas, many industrial firms are increasing the use of coal and alternate fuels such as wood and municipal wastes. The use of these fuels in small combustion devices is impractical due to the expense of pollution control equipment. The development of suitable control systems for small combustion devices will allow the utilization of these fuels with minimal environmental impacts. In addition, diesel engines will likely be used increasingly in small cogeneration applications, particularly to supply space heating and electricity in commercial buildings. Diesel engines may pose a health concern because of their particulate emissions and may be a source of noise pollution.

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SECTION 3

OVERVIEW OF COGENERATION

This section presents an overview of cogeneration, its current status and proposed implementation by the industrial, utility and commercial sector. In order to identify environmental issues and the need for research on the environmental and health impacts of cogeneration it is necessary to assess the projected development of the technology to the extent that it may have some impact. Several studies have been sponsored by the government and utilities, to assess the potential of cogeneration as a means of conserving energy. Some of these study results are summarized in this section as well as the types of cogeneration systems utilized and planned, and the potential constraints to cogeneration development.

COGENERATION POTENTIAL

The future development of cogeneration will be highly dependent upon its acceptance by utilities and industry and will be affected by several factors including the following: economic, technological, environmental, regulatory, and institutional. Despite the potential constraints, several potential users of cogeneration systems have made a commitment to using this technology in future plant and utility service area expansion. The types of cogeneration systems configurations are described below.

Types of Cogeneration Applications

There are several types of cogeneration systems currently available. They are generally classified as either topping or bottoming cycles. In a topping cycle, the energy level required for process heat is relatively low and fuel is burned first to produce either electrical or mechanical power. The heat is then removed from the power production system to be used as process heat. The generator driver in a topping cycle may be either a steam turbine, gas turbine, or diesel engine. In a bottoming cycle, fuel is burned to first produce process heat with the excess heat from the process used to generate electricity or shaft power. Cogeneration systems can be used for in-plant power generation, district heating and industrial parks primarily, but can also be used in total energy systems such as integrated community energy systems. These configurations are as follows:

In-plant power generation--

In this configuration, an industrial plant which is a large consumer of process steam will produce both heat and electrical power for the plant. In some cases, excess electricity can be sold back to the utility by interconnecting with the grid system. Additional fuel use by the plant is required

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for cogeneration compared to producing only process steam. However, electricity is no longer purchased from the utility. Due to increased fuel use at the plant, on-site pollution emissions and waste materials are greater than with conventional steam production. Air pollution emissions reduced by the utility sometimes offsets the increased emissions from cogeneration, if the two plants are in close proximity.

This configuration is currently the most widely used and will most likely continue since it can be implemented by an industrial plant with the least amount of constraints. These constraints are primarily regulatory in nature and are described later in this section.

Industrial park--

This application of cogeneration utilizes a utility plant to supply steam and/or heat to nearby industries. As with other cogeneration systems, this application is also designed to increase thermal energy efficiencies through the utilization of excess steam capacity that may otherwise be condensed and released as an effluent to the environment. The increased energy savings through industrial park cogeneration can serve two purposes: 1) to reduce the overall energy consumed or 2) to allow for future industrial expansion. Industrial park cogeneration is being considered in areas of heavy concentrations of industries within the Tennessee Valley Authority area and the Texas Gulf Coast. The Gulf States Utilities Company has been cogenerating for several years by supplying process steam to several closely located chemical companies near one of its power stations. The impact of the industrial park on the environment is dependent upon the type of fuels used and displaced.

Utility scale district heating--

In a district heating configuration, waste heat in the form of hot water or steam from a utility plant is piped underground to a group of residential or commercial buildings to be used for heating or cooling. This practice has been widespread in Europe for several decades but accounts for less than one percent of the U.S. and Canadian energy use.

There is increasing interest in district heating applications in the U.S. due to its many advantages, however there are certain constraints which must be overcome. Approximately 20 percent of U.S. energy consumption is for residential and commercial space and water heating, with as much as 90 percent of this demand supplied by oil and gas. District heating presents an opportunity for conserving these scarce fuels with a coal fired utility plant.

Advantages of district heating systems include improved air quality, increased energy efficiency, and reliability of an integrated distribution system. Improved air quality is often achieved from reduced fuel use and the use of emission controls at the utility plant whereas there are little or no controls used in residential and commercial facilities. European technology although proven, is not easily adaptable to U.S. utility practice due to several factors: turbine generators are larger in the U.S. utility systems; utilities in Europe peak in winter, rather than in the summer as in the U.S.; and new power plant construction is at a low level in U.S. urban areas.

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National Estimates of Cogeneration Potential

The greatest potential for cogeneration development lies in industries that require large amounts of process steam and/or heat in addition to electricity. The majority of this demand is from the following energy-intensive industries:

- Petroleum refining
- Chemicals
- Pulp and paper
- Steel
- Food
- Stone, clay and glass
- Textiles

Several studies have analyzed the cogeneration potential in these industries with the estimated energy savings in 1985 described below.

Industrial Cogeneration Optimization Program - TRW[(1)]--

This study characterized the energy use profiles of five industries and selected economically viable cogeneration systems for specific industrial plants based on maximum energy savings. The industries studied were food, textiles, pulp and paper, chemicals, and petroleum refining. The total oil and gas savings and net energy savings are presented in Table 3-1. Estimates were also made of the energy savings in each of the nine National Electric Reliability Council (NERC) regions.

TABLE 3-1. POTENTIAL NET ENERGY AND OIL AND GAS SAVINGS FROM COGENERATION IN FIVE INDUSTRIES AT THE NATIONAL LEVEL, EXAJOULES/YEAR (QUADS/YEAR) 1985

Industry	Energy		Oil and gas*	
Food	0.001	(0.001)	0.000	(0.000)
Textiles	0.019	(0.018)	0.039	(0.037)
Pulp and paper	0.263	(0.248)	0.078	(0.074)
Chemicals	0.038	(0.036)	0.458	(0.432)
Petroleum	0.018	(0.017)	0.220	(0.207)
TOTAL POTENTIAL SAVINGS	0.339	(0.320)	0.795	(0.750)

*Includes switching from oil and gas to coal or alternative fuels.

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Energy Industrial Center Study - DOW Chemical[2]--

DOW Chemical served as the project manager for the NSF-sponsored study. DOW examined the potential for cogeneration in four major industries: petroleum refining, pulp and paper, chemicals, and steel. The study concluded that cogeneration was economically and technically justified in these major industries and could save up to 1.62 exajoules (1.58 quads) per year by 1985. The energy savings projected by DOW are significantly higher than those found in any of the other studies because the DOW study assumes that whatever systems are economically viable will be implemented, thus defining the full cogeneration potential in absence of other constraints.

Thermo Electron Corporation (TECO)[7]--

A 1976 study by the Thermo Electron Corporation examined cogeneration for the chemical, petroleum refining, and pulp and paper industries. Topping cycle cogeneration was examined for steam and gas turbines, as well as diesel engines.

The potential energy savings for these industries, using steam turbine topping cycles under current economic conditions for industry, were estimated to be as follows:

Industry	Net savings (1985) Exajoules/year	(QUADS/year)
Petroleum refining	0.038	(0.036)
Pulp & paper	0.297	(0.281)
Chemical	0.132	(0.125)
TOTAL	0.467	(0.442)

Although TECO found that larger potential savings are available from the use of a gas turbine or diesel topping system, it was recognized that these systems currently use oil or natural gas fuels.

Resource Planning Associates, Inc (RPA)[3]--

This study of cogeneration covered six energy-intensive industries. These were: food, textiles, pulp and paper, chemical, petroleum refining, and steel. The study estimated that up to 0.61 exajoules (0.59 quads) per year could be saved by cogeneration with steam topping and up to 0.31 exajoules (0.29 quads) per year by direct heat topping cogeneration. The RPA report provides estimates of the expected generation of process steam in each industry. These were used to estimate the expected savings by industry as shown below. Industrial energy savings were assumed to be proportional to the steam generated. The expected savings for steam topping cogeneration in the six industries selected for the study were estimated to be as follows:

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Industry	Net savings (1985) Exajoules/year	(Quads/year)
Food	0.01	(0.01)
Textiles	Negligible	Negligible
Pulp & paper	0.34	(0.32)
Chemicals	0.13	(0.12)
Petroleum	0.05	(0.05)
Steel	0.10	(0.09)
TOTAL	0.63	(0.59)

General Accounting Office[8]--

This study examined energy savings potential with cogeneration in the pulp and paper, chemical and petroleum refining industries under four scenarios. The analysis indicated that the most reasonable and likely attainment of energy savings from cogeneration in 1985 would be from 0.51 to 0.80 exajoules (0.48 to 0.75 quads).

As shown in these studies, there is a significant variation in the estimates of energy savings from cogeneration. Regardless of the differences, interest in cogeneration is increasing and presents the potential development of a conservation measure of which EPA must be cognizant. The development of this measure will rely primarily on the utilization of conventional methods of electricity and steam/heat energy production; i.e., steam turbines, diesel engines and gas turbines.

COGENERATION CYCLES

Most of the cogeneration systems currently used and planned for the near term are modifications of technologies that have been used for decades by the steam and electric power generating industry. These technologies include steam turbines, gas turbines, combined steam and gas turbine cycles, and diesel engines as the prime movers. One of the factors that will influence the mix of cogeneration technology which develops in the United States over the next 10 to 20 years will be the economic incentives for cogenerating electricity. The Department of Energy has provided one set of estimates of cogeneration energy conversion technology mixes that might result depending on the relative amount of electric power which is cogenerated.[6] The variation of technology mix with amount of electric power produced is shown in Table 3-2 for two types of cogeneration applications: production of process steam and production of process heat. It is evident that the backpressure steam turbine will be the predominant technology for process steam, with the gas turbine being used for the cogeneration of process heat and electric power.

The environmental impacts of cogeneration therefore must focus on the technologies for steam and power generation since these will continue

TABLE 3-2. COGENERATION TECHNOLOGY MIX ESTIMATES FOR DIFFERENT RELATIVE AMOUNTS OF ELECTRIC POWER PRODUCTION (a)

COGENERATION APPLICATION	AMOUNT OF ELECTRIC POWER PRODUCTION		COGENERATION TECHNOLOGY
	Low Electric Power Production	High Electric Power Production	
Process Steam	1.0	0.75	Backpressure Steam Turbine
	0.0	0.15	Gas Turbine
	0.0	0.10	Diesel
Process Heat	-	1.00	Gas Turbine

(a) Source: Commercialization Strategy Report for Cogeneration, Department of Energy Task Force, December, 1978

to be used, with new technologies to be developed by the year 2000. The pollutant residuals produced by these technologies in a cogeneration system are basically the same as in conventional applications, except that with cogeneration additional fuel is consumed on-site leading to potential environmental problems, if the system is located in an urban area, or where environmental quality is already being degraded. The increased efficiency of cogeneration however, results in less pollutants for the same amount of energy produced in a conventional system. This results in decreased air emissions, solid wastes and thermal discharges at the utility plant where fuel use is being displaced. Solid waste discharges are reduced primarily as a result of the materials used in control systems such as in lime/limestone scrubbing and the bottom ash in boilers which are a function of the amount of fuels consumed.

Some new technologies being considered for electricity generation and which have improved environmental control efficiencies include fluidized bed combustion, Stirling engines and fuel cells, with the first having the greater near term potential. A brief description of these technologies is presented below.

Steam Turbines

The steam turbine systems consist of a boiler and a backpressure turbine with the boiler being fired primarily by coal, oil, or natural gas. Cogeneration systems are currently being planned which also burn wood wastes in combination with coal, municipal solid waste and industrial by-products. The use of these latter fuels may require additional control technology. Steam generating plants used in industry and by utilities are currently regulated by New Source Performance Standards (NSPS) for emissions of sulfur dioxide, suspended particulates and nitrogen oxides. These regulations apply to boilers having a heat input rate greater than 264 gigajoules per hour (73 MW). Industrial cogeneration facilities that sell less than 25 MW of electricity or less than one-third of their potential electrical output capacity are not regulated under the utility standards but by the steam generating unit standards. Steam turbine systems are generally economically feasible for large size boilers, i.e., over 10 MW. There are currently no federal emission standards for boilers of this size although EPA is presently in the process of developing NSPS for industrial boilers. It is not known at this time how cogeneration facilities will be affected by these standards.

A primary disadvantage of utility steam turbine systems is their low efficiency in producing electricity, which contributes large amounts of waste materials per unit of energy produced. The overall efficiency of a steam turbine cogeneration system is approximately 65 to 85 percent compared with conventional power production at approximately 35 percent. The steam turbine system produces less electricity per unit of process steam than other cycles such as diesels and some gas turbines.

Gas Turbines

The gas turbine cogeneration system consists of a natural gas or distillate oil fired turbine and a waste heat recovery unit. The electric

utility industry has been increasing the use of gas turbines in the last decade, and industry has been using them increasingly for gas compression and standby power. Turbines range in size from less than 0.03 MW to over 75 MW. Gas turbines under 3.7 MW are used primarily in gas compression and standby power applications. Medium capacity turbines, between 3.7 and 15 MW are employed in a wide variety of applications including mechanical drive and shaft power. Gas turbines over 15 MW are used almost exclusively in electric generator drive applications. Over 90 percent of the horsepower sold in the U.S. goes to utilities and that trend is expected to continue. Environmental problems associated with these turbines in cogeneration will be similar to those experienced in electricity generation applications.

In gas turbine cogeneration, the combustion gases produce mechanical shaft power, while the hot exhaust gases can be used to raise steam in a waste heat boiler. If process steam is needed at high pressures then the steam can be supplied directly to the industrial process. In cases of low pressure steam demand the waste heat boiler can be fitted with a backpressure steam turbine to produce additional electricity. Although the electrical conversion efficiency of a gas turbine topping cycle is lower than that of steam turbines, gas turbines can produce about 4 to 6 times as much electricity for the same amount of process steam.

In addition to oil and gas combustion in gas turbine systems, alternate fuels are also being considered for these technologies. In Los Angeles, a planned cogeneration unit at a sewage treatment plant will utilize gas from a sewage sludge digester to operate a gas turbine. A wood waste fired combustor and an indirectly fired turbine is being studied for use in a paper mill in Anderson, California.

Diesel Engine

In a diesel engine topping cycle, the engine drives a generator to produce electricity with the high temperature exhaust gases used in a heat recovery boiler to raise steam as with the gas turbine systems. Diesel engine cycles are particularly useful for low power requirement applications up to 25 MW, with systems under 10 MW being the most commonly used. This cycle is the most efficient of the three topping systems in producing electricity, and is most useful when a high rate of electricity with little steam is desired.

New Technologies

Fluidized bed combustion (FBC)--

Fluidized bed combustion involves the direct combustion of coal in a fluid bed which can contain a sulfur sorbent of limestone or dolomite. FBC offers industry and utilities the option of using coal with a combustion system capable of controlling sulfur dioxide emissions more effectively than conventional combustion systems. In addition, nitrogen oxides emissions are lowered due to the lower combustion temperatures with FBC.

In a cogeneration application, excess combustion gases are drawn through a waste heat recovery boiler and raised to steam temperature for process use. In addition, steam from an intermediate pressure turbine can also be used for process.

Fuel cells--

Fuel cell technology is adaptable to a wide variety of fuels including coal-derived liquids and gases, natural gas and liquid petroleum distillates. The fuels are converted to a hydrogen rich gas which is electrochemically combined with oxygen from the air. The first generation fuel cell utilizes phosphoric acid and has achieved an efficiency of 38 to 40 percent. Waste heat from the fuel cell may be used to provide hot water and/or steam for industrial cogeneration. The phosphoric acid fuel cell can be used in 5 to 10 MW modules for installations up to 200 MW. The second generation fuel cell utilizes molten carbonate and may have efficiencies up to 50 to 55 percent and, in a cogeneration application, the efficiency may be as high as 85 percent. The molten carbonate fuel cell can be used for large installations in a number of cogeneration applications including industrial process heat, energy parks and district heating due to the ability to use them in dispersed power generation applications. Waste heat is available at much higher temperatures than from conventional steam turbines, thereby increasing their efficiency.

Stirling engine--

The Stirling engine is an external combustion piston engine based on a closed cycle system, converting heat into mechanical power. Mechanical energy is usually extracted from the system by means of a rotating shaft. The greatest advantage of a Stirling engine over other prime movers is its multiple fuel capability. It has the ability to operate on solar energy, process waste heat and all liquid and solid fossil fuels. It is expected that synthetic fuels will also be applicable for use in these engines. A test program using a Stirling engine in a typical residential complex, hospital, and office buildings was conducted which indicated an energy savings of 29 to 33 percent over a conventional system for the residential and hospital complexes, and only 5 percent for the office building.[9]

The Argonne National Laboratory has recently initiated a program under DOE sponsorship for stationary Stirling engines, to develop the technology base for externally fired prime movers. Major emphasis is on the development of engines in the 0.37 to 2.25 MW range for several stationary power applications including cogeneration.

POTENTIAL CONSTRAINTS TO COGENERATION

The development of any new technology is subject to various constraints dealing with economic, environmental, technical, institutional and regulatory issues. These constraints are also applicable to cogeneration and have been described extensively in previous documentation. They are summarized briefly below to show their interrelationship.

Economic Constraints

Economics may be the most significant issue affecting the acceptance of cogeneration. As with any business, cogeneration is subject to the same criteria for production capability and earnings potential. In-plant cogeneration by industries will be most affected by economic considerations since industrial companies have indicated that the economic rate of return on investment is the most important investment decision criterion. The major factors affecting the rate of return on investment are capital costs and cost savings realized from cogeneration in comparison to the alternative cost of separate operation.

Capital costs are dependent upon the type of cogeneration configuration and the size of the plant. Due to economies of scale, cogeneration systems under 10 MW employing steam turbines are very expensive and may be prohibitive.

Cost savings depend on the extent that cogeneration capacity is used, fuel costs, and costs of electricity from alternate sources. Cogeneration systems are most efficient when operated at design load capacity, producing both steam and electricity. An imbalance between steam and electricity demands will decrease efficiency and increase operating costs. Electricity costs also offset the cost savings derived through cogeneration. Since cogeneration enables industry to replace purchased electrical power with cogenerated power, the cost savings are greatest when electricity costs are high. On the other hand, some industries may be able to purchase electricity cheaper than they can generate it, and also eliminate the liability of being responsible for supplying excess electricity to the utility. Economic issues are closely related to environmental, regulatory and institutional requirements as these each impact both capital and operating costs.

Environmental Constraints

The use of cogeneration may have environmental benefits-particularly in terms of emission reductions-when compared to the total pollutants produced from sources which separately generate process steam and electricity. These benefits arise from reduction in fuel consumption at the utility or, sometimes, at the industrial site. However, pollutant production will usually increase at the cogeneration plant due to increased fuel use. Therefore, unless the cogeneration plant and off-loaded utility plant are in close proximity, there may be little or no benefit locally. In addition, the utility plant is not obligated to reduce power output and may sell the excess power created by the cogeneration system to another customer, thereby not reducing fuel use or emissions locally at all.

Air pollution regulations will be the environmental constraint on most cogeneration systems. A new cogeneration system or modifications of an existing plant to a cogeneration system will usually be large enough to be subject to new source review requirements at both federal and state level. The major Clean Air Act provisions affecting fuel burning installations are non-attainment area requirements and Prevention of Significant Deterioration (PSD) regulations. Cogeneration systems planning to locate in areas where air quality regulations are in violation (i.e. non-attainment areas) would have difficulties obtaining permits unless emission offsets from another source are obtained.

PSD regulations are intended to insure that existing air quality in areas which meet standards is not significantly degradated by new source construction or source modification. PSD regulations require that best available control technology (BACT) be used for all sources requesting a PSD permit.

While an individual cogeneration system may be able to obtain construction and operating permits, the development of numerous systems may be limited because of high existing pollution levels. A recent air quality modeling analysis for adding 395 diesel engine cogeneration systems in New York indicated that violations of the air quality standards could occur[10]

In industrial park cogeneration, air quality regulations may constrain the number of facilities that can be placed in the park and the types of fuels that can be fired. Energy parks using a nuclear power station have been considered for several applications; however, the current outlook for the nuclear industry has been clouded due to the recent accident at the Three Mile Island nuclear facility in Pennsylvania. Advantages of nuclear units for cogeneration systems compared with fossil fuel combustion are reduced conventional air and solid waste pollution.

Technical Constraints

The major technical constraints to cogeneration involve the availability and reliability of process steam and electricity delivery between the industrial and utility plants. Cogeneration is usually uneconomical for producing process heat or steam for plants having a low demand. This would especially apply in industrial parks where a utility steam turbine would be supplying process steam to one or more industrial plants. Steam loads below 6.3 kilograms per second (50,000 pounds per hour) are not practical for steam turbine systems, or below 1.9 kilograms per second (15,000 pounds per hour) for gas turbine and diesel systems. Another constraint is the impact on the efficiency of cogeneration systems, since the extraction of steam at high pressure can downgrade electrical efficiency. A constraint which is both technical and regulatory concerns the type of fuel used in cogeneration systems. Many of the smaller systems are designed for oil or natural gas combustion; however, the use of these scarce fuels is counter to current energy policy, which is discouraging their use.

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Institutional Constraints

A major institutional issue is the ownership of the cogeneration system, whether it is the utility, industry, or a third party. The type of ownership will determine regulatory constraints on the price of selling steam, heat, or electricity. Since ownership also implies control, there is a reluctance by industries to tie the operation of their facilities to another industry or a utility over which they would have limited or no control. Long term commitments to cogeneration would be difficult to obtain under these conditions, thereby reducing the incentive for developing a cogeneration plant with a useful life of 20 to 30 years.

The potential constraints to cogeneration have been briefly described to indicate the extent to which cogeneration may be affected. It also indicates that environmental issues are not necessarily the major constraint, and in some cases, would have little if any impacts. Although some of the constraints can be adverse, there are none that cannot be mitigated depending upon the amount of interest in developing cogeneration by both government and industry. As there are several cogeneration plants currently under development, it is apparent that the issues described above have been resolved. On the other hand, these same issues have caused the cancellation of a major cogeneration project in Texas and have discouraged some potential cogeneration users in the Tennessee Valley Authority service area.

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SECTION 4

ENVIRONMENTAL ANALYSIS OF COGENERATION SYSTEMS

This section provides an environmental analysis of five industrial cogeneration systems and one for an industrial park. In addition, an air pollution emissions assessment based on energy savings potential is presented for three regions, the Tennessee Valley Authority service area, the New England area, and a utility company of New Jersey service area. A methodology for expanding these results to a national level is presented in Section 5.2.

ANALYSIS OF IMPACTS FROM REFERENCE CASES FOR IN-PLANT POWER GENERATION AND INDUSTRIAL PARKS

An analysis of the environmental impacts from several reference cogeneration cases was performed for this study. The emphasis of the analysis has been placed on in-plant power generation for industrial processes since this has the greatest growth potential for cogeneration and is also currently the most widely used application. The reference cases analyzed were for specific industrial plants in the following industries: speciality chemicals, food, textiles, paper and pulp, and petroleum refining. The actual plants have not been identified for reasons of confidentiality. The emphasis of the analysis is on the air pollutant emissions since they are expected to cause the most significant impacts of new or modified fuel burning installations. The 1977 Clear Air Act amendments have been cited by potential industrial and utility cogeneration users as being a limiting factor in assessing the potential for cogeneration. The water pollution, solid waste and thermal impacts were analyzed for one case.

The following factors were considered for the air quality analysis:

(1) Types, characteristics, and quantities of fuel used in the industrial plant, with and without the new cogeneration system,

(2) Performance characteristics of the environmental control systems used in the industrial plant, with and without the new cogeneration system,

(3) Current air quality attainment status for the Air Quality Control Region (AQCR) containing the industrial plant,

(4) Types, characteristics, and quantities of utility primary fuels displaced by the new industrial cogeneration system,

(5) Performance characteristics of environmental control systems used in the utility central station plants where fuel displacements occur,

(6) Locations of the utility central station plants with respect to the AQCR containing the industrial plant.

From data pertaining to factors (1) and (2) above, the changes in industrial plant emissions due to cogeneration can be calculated, and air emissions data relating to factor (3) can then be used to determine whether nonattainment area regulations would apply in implementing the cogeneration system. Data relating to factors (4) and (5) can be used to estimate the reduction in utility plant emissions due to reduced central station generation. Finally, the geographic considerations of factor (6) can be used to estimate net emissions changes within the AQCR which may also affect cogeneration implementation.

This assessment procedure, although a relatively simple concept, is difficult to execute within the limits of readily available data. In keeping with the site-specific nature of this study, a substantial effort was made to acquire actual data on the specific industrial plants and utilities involved. However, data gaps still remained, and a number of assumptions had to be made, as discussed in the individual assessments which follow. Table 4-1 shows the energy savings projections for each of the five plants.

Chemicals Plant, Institute, West Virginia

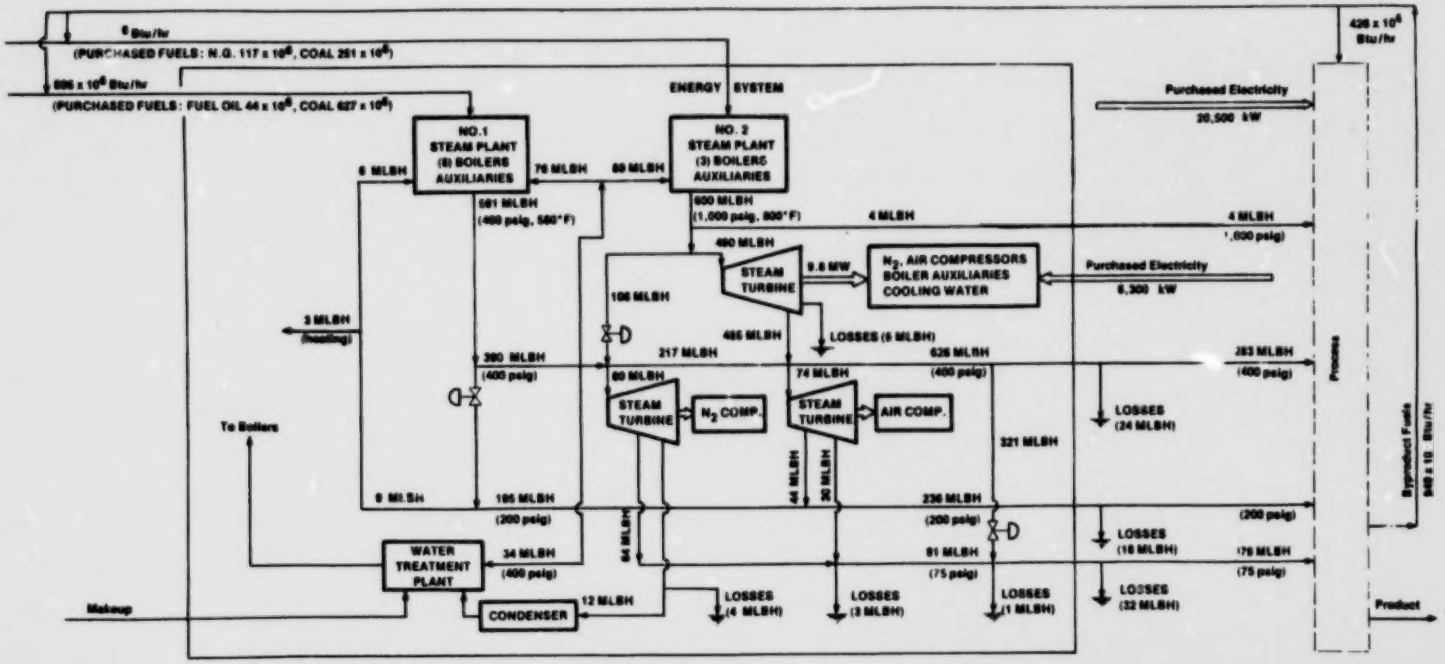
The cogeneration system selected for this plant is a 7.9 MW extraction/backpressure steam turbine which will be interposed between the 2.76 and 5.17 megapascals (75 and 200 psig) headers, and will replace existing throttling valves in the steam distribution system. Diagrams of the existing system and the cogeneration option are shown in Figures 4-1 and 4-2. Although no new boilers are required, additional coal must be fired in the existing boilers. On an annual basis, the cogeneration system will require an additional 292,070 gigajoules (276,826 MM Btu) of energy in the form of coal which is the fuel currently used and will displace 697,740 gigajoules (661,325 MM Btu) of coal used by the utility. The coal recently fired at the chemical plant contained less than 1 percent sulfur. The boilers are equipped with electrostatic precipitators. Therefore it was assumed that no new emission controls would be required.

Emission estimates for five criteria air pollutants were made for the chemical plant on the basis of the quality of the coal and existing emissions controls as well as for the utility plants at which fuel use would be displaced. Results of these emissions estimates and for an off-loaded utility plant are presented in Table 4-2.

TABLE 4-1. ENERGY SAVINGS FROM REFERENCE COGENERATION PLANTS

Facility/ Cogeneration System	Facility Energy Saving (Gigajoules/yr)[a]		Utility Energy Savings (Gigajoules/yr)		Net Energy Savings (Gigajoules/yr)
A. Specialty Chemicals/ Steam Turbine	Coal:	- 292,070	Coal:	697,740	405,670
B. Textile Plant/ Steam Turbine	Resid. Oil:	499,460	Coal/NUC:	465,410	368,230
	Gas:	455,360			
	Coal:	-1,052,000			
		- 97,180			
C. Refinery/ Steam Turbine	Resid. Oil:	5,216,200	Oil/Gas:	1,062,060	386,830
	Coal:	-5,891,430			
		- 675,230			
D. Food Processing/ Gas Turbine	Gas:	-43,480	Coal:	81,360	52,280
	Resid. Oil:	14,400			
		-29,080			
E. Paper Plant/ Steam Turbine	Resid. Oil:	5,413,490	Coal/NUC:	1,571,090	460,110
	Gas:	3,467,970			
	Wood:	-8,223,110			
	Coal:	-1,769,300			
		-1,110,970			

[a]Negative number signifies increased energy use.



Note: MLBH = Million pounds per hour.

Figure 4-1. Site-specific Chemicals Plant - Institute, West Virginia (Base Case)

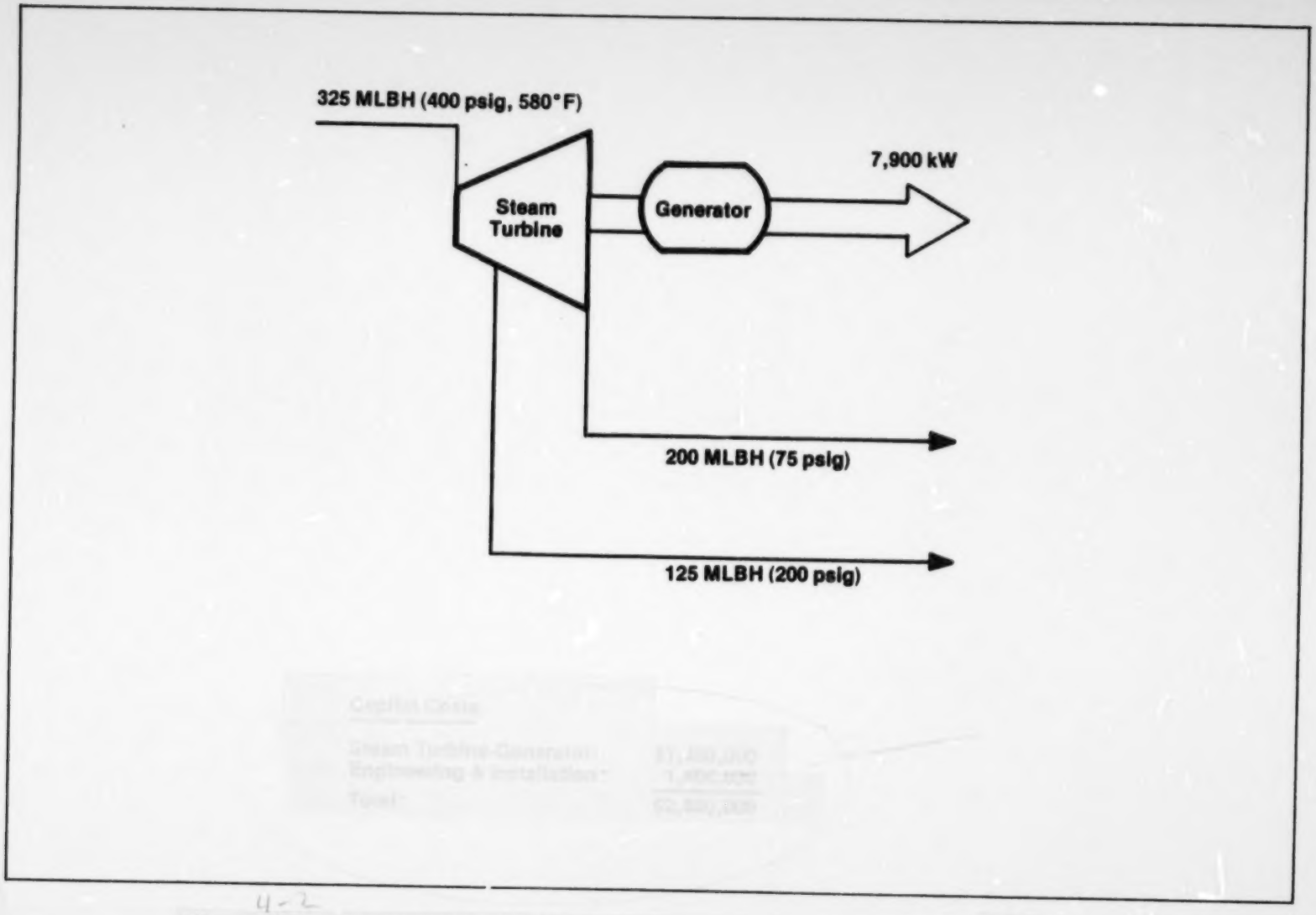


Figure 4-2. Specialty Chemicals Plant, Cogeneration System Option

TABLE 4-2. REGIONAL AIR POLLUTION EMISSIONS ANALYSIS FOR CHEMICALS PLANT

Pollutant	Incremental Emissions, Megagrams/Year (Tons/Year)					
	Cogeneration Plant*		Utility Plant**		Net Change***	
TSP	+ 21	(+23)	- 46	(-51)	-25	(-28)
SO_2	+182	(+201)	-495	(-546)	-313	(-345)
NO_x	+ 96	(+106)	-235	(-259)	-139	(-153)
CO	+ 5	(+6)	- 13	(-14)	- 8	(-8)
HC	+ 2	(+2)	- 4	(-4)	- 2	(-2)

*Cogeneration Plant Data
Coal HHV = 27.5 megajoules/kilogram (11,800 Btu/pound)
Coal %S = 0.90
Coal %Ash = 12.0
Precipitators Used for Particulate Control = 98% efficiency

**Utility Assumptions
Coal HHV = 26.7 megajoules/kilogram (11,500 Btu/pound)
Coal %S = 1.0
Coal %Ash = 11
No controls except for precipitators = 98% efficiency

***Net Change = Change in emissions associated with producing a fixed amount of useful energy which results from converting a heat-only boiler to a cogenerating unit (and concurrently reducing the load on the utility plant).

The plant consists of several fossil fuel boilers with combined energy input of more than 267 megajoules/hour (250 MMBtu/hr) and is a major stationary source. In changing to cogeneration both sulfur dioxide and nitrogen oxide emissions will increase above the de minimus levels for prevention of significant deterioration.* However, increased emissions are only due to an increase in the firing rate for the boilers; no physical change in the boilers will take place. Therefore this development of a cogeneration system using existing boilers is specifically excluded from PSD review and from requirements of Best Available Control Technology (BACT).

The significance of the net reductions depends upon whether the utility plant affected is in the same AQCR (Kanawha Valley Intrastate) as the cogeneration plant and whether the cogeneration plant emissions are influenced by the utility plant. The reduction in emissions at the utility (Appalachia Power Company) plant are greater than the emissions from the cogeneration plant for each of the five pollutants, providing an offset. There are two coal fired utility plants within the AQCR and several others within 161 kilometers (100 miles). Although the utility company practices economic dispatch, these plants have similar capacity factors and operating costs as shown in Table 4-3. It is difficult to determine, therefore, which plant would be off-loaded. Assuming that dispatch is based on operating cost, the most likely candidate is the Sporn plant which is located outside of the AQCR. This off-loading would probably not benefit the Kanawha Valley AQCR but would reduce overall emissions within the Appalachian Power Company service territory. If a utility plant within the AQCR was off-loaded, then a net decrease in each of the pollutants could occur. The utility is not obligated to reduce its emissions and could, theoretically, sell this excess power to another customer in its service area, thereby not achieving any emissions reduction.**

The Kanawha Valley Intrastate AQCR is classified as a nonattainment area for suspended particles and photochemical oxidants. As with PSD review, the sources will be exempt from nonattainment regulations because emission increases result only from increased load factors of the boilers. (In addition, the switch to cogeneration does not result in enough of an increase of either of these pollutants to pass the de minimus threshold. Thus the increase in emissions is not considered significant under nonattainment regulations).

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*For a complete explanation of the applicability of prevention-of-significant-deterioration (PSD) regulation, the reader is referred to "Prevention of Significant Deterioration: Workshop Manual," EPA 450-2-80-081 (October 1981).

**There is also concern that utilities may decrease the rate at which they retire older, more polluting plants if, for whatever reason, the rate of growth of electricity demand decreases. This result of cogeneration development is not considered in this study, but could have a net negative environmental impact.

TABLE 4-3. UTILITY PLANT CAPACITY FACTORS AND OPERATING FOR APPALACHIAN POWER COMPANY PLANTS

Plant	Capacity factor	Operating Cost Mills/megajoule	(Mills/kWh)
Kanawha River	0.77	3.15	(11.33)
Glen Lynn	0.61	3.72	(13.39)
Clinch River	0.72	3.70	(13.33)
Philip Sporn	0.47	4.03	(14.50)
John E. Amos	0.63	3.54	(12.76)

Source: FERC Form 1 (1977)

Additional environmental impacts from a coal fired cogeneration system or steam turbine system include solid wastes, water pollutants and thermal pollution. Solid wastes are generated primarily from flue gas desulfurization systems of both the regenerable and non-regenerable type. The non-regenerable or "throwaway" systems have been used by utility and industrial plants to meet NSPS for sulfur dioxide emissions with the most widely used systems consisting of a lime/limestone process.

Water pollution impacts from fuel combustion include those from the process and the chemical compounds used in steam generating plants. Process waste water sources include non-recirculating main condenser cooling water, blowdown from recirculating main cooling water system, non-recirculating ash reducing systems and wet scrubber air pollution control systems. There are, in addition, several low volume waste water sources such as clarifier and evaporator water treatment, condensate treatment and boiler blowdown.

Numerous chemicals are used in steam plants for such uses as coagulants in clarification water treatment corrosion inhibition or scale prevention in boilers and cooling towers, pH control in boilers and cooling towers, boiler cleaning and biocides in cooling towers.

Significant thermal discharges from steam plants occur when heat is not converted to energy but is ejected into the atmosphere or water waste stream. Power plant efficiencies are generally under 40 percent with the remainder of the heat being ejected, most of it to cooling water. In a cogeneration system, the waste heat can be utilized for producing low grade steam for process uses, thereby reducing the amount of thermal discharge into receiving waters.

Table 4-4 presents the net change in solid waste, water pollutants and thermal discharges that would occur from the cogeneration system considered for the chemical plant. Estimates of pollution reductions at the utility plant have been made for both an existing plant without controls and a new plant with controls and a cogeneration plant meeting all applicable environmental performance standards. When compared to an existing utility plant, the new cogeneration plant may have greater impacts even though the plant is under more stringent controls. For example, in solid waste generation, an existing utility plant without sulfur dioxide controls such as a lime/ limestone FGD system, would generate only bottom ash with the rest of the waste materials emitted through the stack, therefore producing less solid waste than the cogeneration system which may utilize flue gas cleaning. Compared with the new plant, however, the cogeneration plant solid wastes will be significantly offset as shown in Table 4-4. Net thermal pollution is decreased by going to cogeneration, no matter what type of utility is displaced.

Textiles Plant, Cheraw, South Carolina

In this plant, a 5.25 MW steam turbine firing coal has been selected for a cogeneration system which will replace an oil and gas fired boiler which is producing process steam. Coal was chosen due to the uncertainty of the future availability of the latter fuels. Low sulfur coal is currently fired in another boiler at the plant for finishing operations. Figures 4-3 and 4-4 show the base case and cogeneration configurations, respectively. Since the use of coal will replace cleaner fuels, air pollution emissions will be higher. Table 4-5 presents these emission changes and indicates that each of the five pollutants will have increased emissions due to coal firing, with sulfur and nitrogen dioxide both increasing in excess of 91 megagrams per year (100 tons per year).

TABLE 4-4. ENVIRONMENTAL RESIDUALS FROM COGENERATION SYSTEM AT CHEMICALS PLANT COMPARED WITH EXISTING AND NEW UTILITY PLANTS (UNITS IN MEGAGRAMS/YEAR)*

	Cogeneration Plant	Existing Utility Plant	New Utility Plant
Solid Waste	+3,741	-3,029	-8,938
Water Pollution			
Suspended solids	+3	-4	-3
Organics	+1	-1	----
Thermal Pollution	$+8.8 \times 10^{10}$	-3.2×10^{11}	-2.1×10^{11}

*Utility plant residuals represent reductions that would occur as a result of displaced fuels.

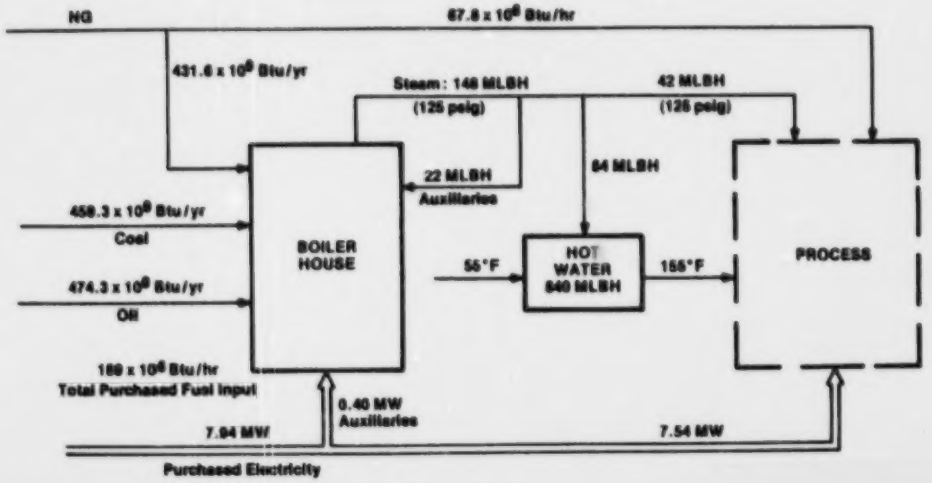

Figure 4-3. Site-specific Textile Plants - Cheraw, South Carolina (Base Case)

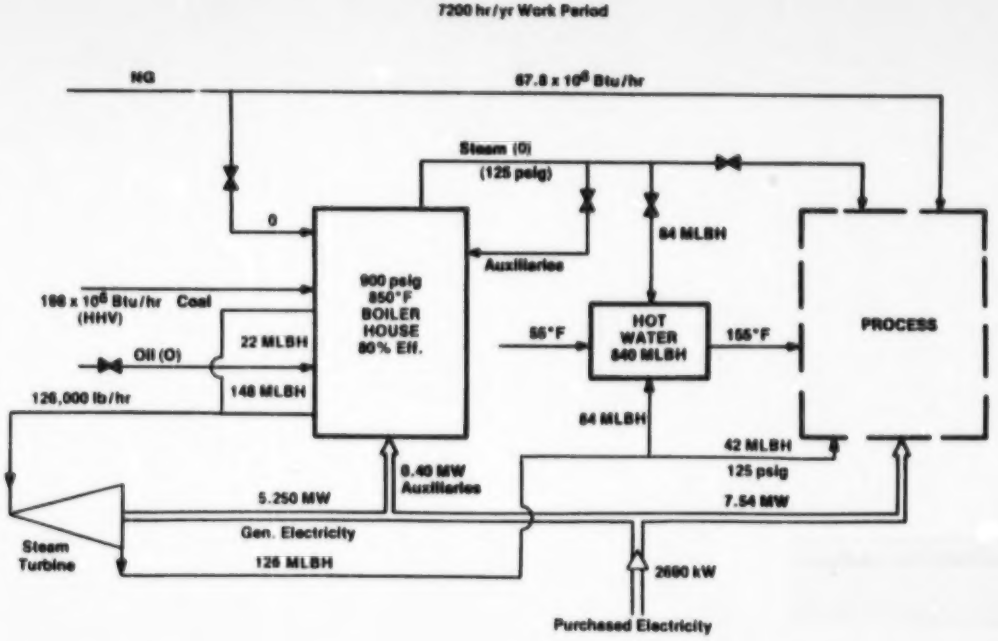

Figure 4-4. Site-specific Textile Plant - Cheraw, South Carolina Cogeneration Option

TABLE 4-5. EMISSIONS CHANGES DUE TO NEW BOILER AND FUEL SWITCHING AT TEXTILES PLANT (MEGAGRAMS/YEAR)

Pollutant	Coal*	Oil**	Natural gas	Net Change
TSP	+ 79	- 14	- 2	+ 63
SO_2	+546	-180	0	+366
NO_x	+305	- 86	-34	+185
CO	+ 17	- 7	- 3	+ 7
HC	+ 5	- 1	0	+ 4

*Coal Data: HHV = 31.1 megajoules/kilogram (13,373 Btu/lb)
Coal %S = 0.85
Coal % Ash = 5.85
Particulate Removal Efficiency = 95 percent

**Residual Oil Sulfur Content = 0.8 percent, no other emission controls.

The emissions estimates were based on the current particulate control efficiency of 95 percent, and the continued use of low sulfur coal for the cogeneration system as the conceptual design for the system includes particulate controls but no scrubbers.

The textile plant is located in the Florence Intrastate AQCR which is currently attaining the air quality standards for all pollutants; therefore, the PSD regulations are the only requirement that must be met. Although the plant boilers consume less than a total of 264 gigajoules (250 mm Btu) of coal hourly, the addition of a coal-fired boiler results in an increase of 366 megagrams/year (403 tons/year) of sulfur dioxide emissions. Therefore the facility is considered a major stationary source and must undergo PSD review for sulfur dioxide, nitrogen oxides and total suspended particulates because increases in these pollutant emissions exceed de miniums thresholds. The additional 366 megagrams (400 tons) per year of SO_2 emissions from the plant represents approximately 2.5 percent of the total annual emissions for the AQCR. Emissions of the remaining pollutants account for less than one percent of the AQCR totals.

Emissions reductions at the Carolina Power and Light Company central station plants have been calculated on the basis of displacing coal. There is a nuclear/fossil steam plant located near the textile plant, and assuming that this plant would be displaced by the cogeneration plant, significant offsets for each of the pollutants could be achieved. Table 4-6 presents the emissions displaced by the utility and indicates that there is still a new increase in each of the pollutants with the exception of carbon monoxide.

TABLE 4-6. NET REGIONAL EMISSIONS CHANGE DUE TO COGENERATION AT TEXTILE PLANT (MEGAGRAMS/YEAR)

Pollutant	Textile plant	Utility*	Net Change
TSP	+ 63	-41	+22
SO_x	+366	-276	+90
NO_x	+185	-154	+31
CO	+ 7	- 9	- 2
HC	+ 4	- 2	+ 2

*Utility Data: Coal Sulfur Content = 0.85 percent
Coal Ash Content = 6.0 percent, Particulate Collection Efficiency = 95 percent.

Although increased efficiencies are achieved by the cogeneration system, net emissions are higher due to the savings of clean fuels and the emission reductions due to them as opposed to the previous case in which coal displaced coal. This case indicates that environmental impacts of cogeneration are a function of the fuels used by the cogeneration plant and utility as well as increased efficiencies.

Food and Kindred Products, Kansas City, Missouri

In this plant, a natural gas fired gas turbine cogeneration system of 0.88 MW is planned which will displace a distillate oil steam system currently used. The base case and cogeneration option are depicted in Figures 4-5 and 4-6, respectively. Increased natural gas use will amount to 43,480 gigajoules per year (41,210 MM Btu per year) and will replace 14,400 gigajoules per year (13,650 MM Btu per year) of distillate oil use. The emissions from the installation of the cogeneration system are shown in Table 4-7 and indicates that the emissions of each of the five pollutants to be insignificant. Neither the PSD nor the non-attainment area regulations would have to be met by the plant for the incremental emissions change due to the plant modification. The utility plants in the Kansas City Power and Light Company service area burn coal primarily. The emissions reductions at the utility are small due to the amount of electricity required by the food product plant. A total of 81,360 gigajoules (77,111 MM Btu) of coal energy will be displaced at the utility plant resulting in net decrease of particulate, sulfur dioxide and nitrogen dioxide emissions as indicated in Table 4-8.

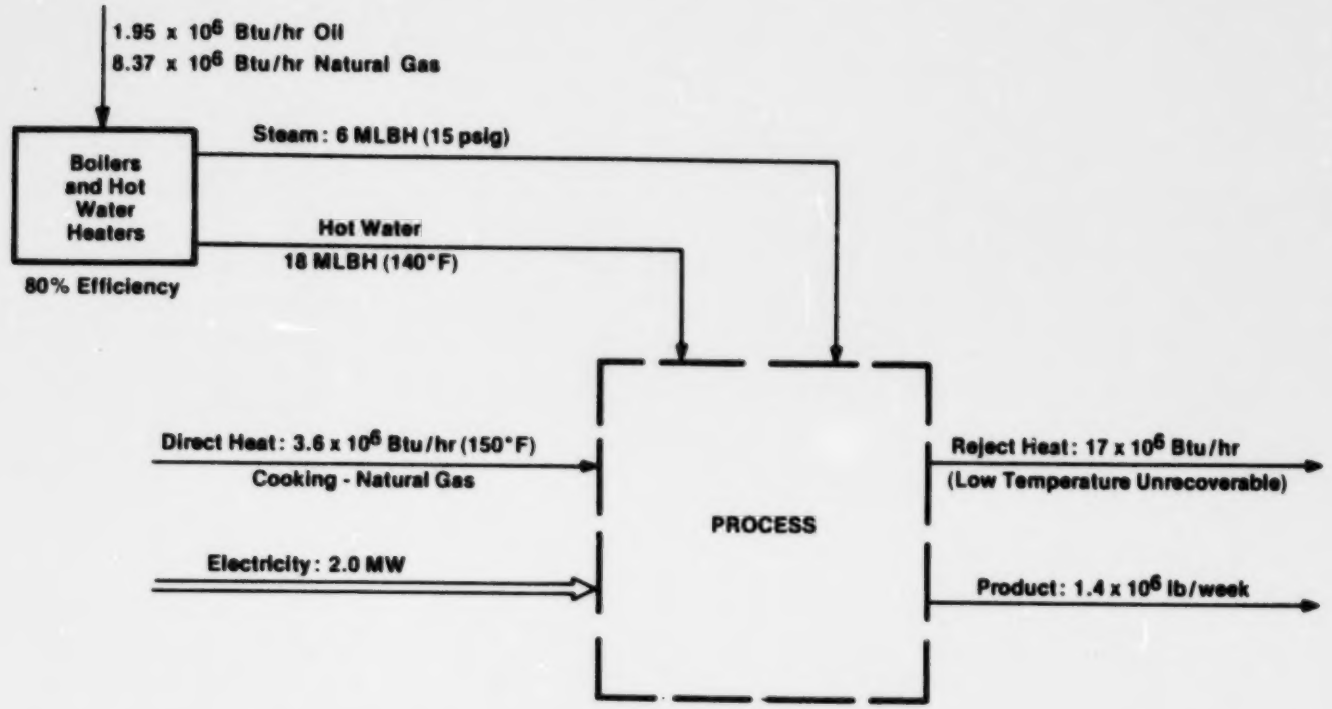
1.95 x 10^6 Btu/hr Oil
8.37 x 10^6 Btu/hr Natural Gas
Boilers and Hot Water Heaters
80% Efficiency
Steam: 6 MLBH (15 psig)
Hot Water
18 MLBH (140°F)
Direct Heat: 3.6 x 10^6 Btu/hr (150°F)
Cooking - Natural Gas
Electricity: 2.0 MW
PROCESS
Reject Heat: 17 x 10^6 Btu/hr
(Low Temperature Unrecoverable)
Product: 1.4 x 10^6 lb/week

Figure 4-5. Site-specific Meat Packing Plant - Kansas City, Missouri (Base Case)

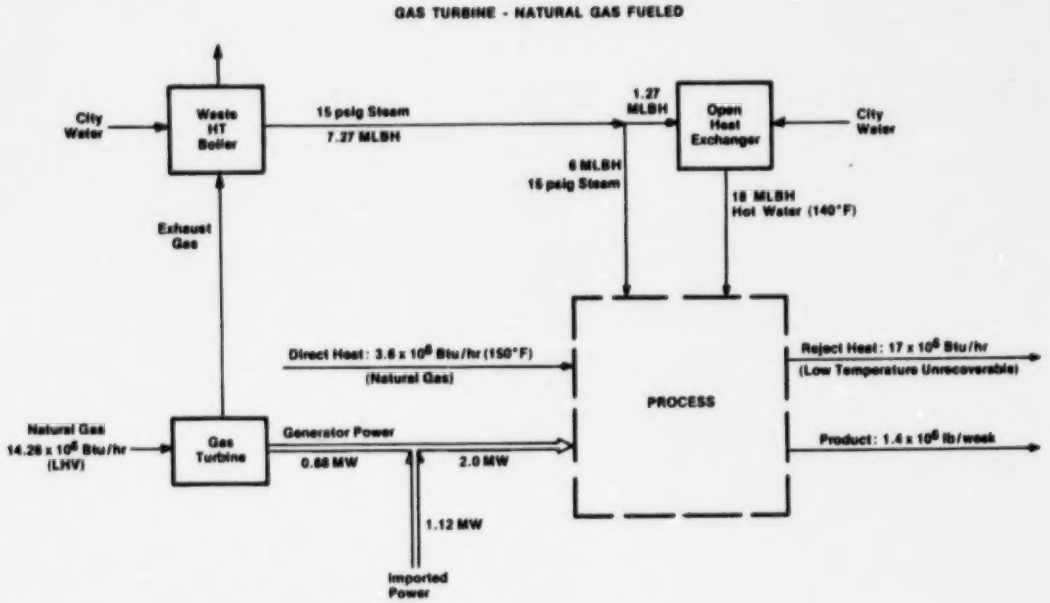

Figure 4-6. Site-specific Meat Packing Plant - Kansas City, Missouri Cogeneration Option

TABLE 4-7. EMISSIONS CHANGES AT MEAT PACKING PLANT DUE TO FUEL SWITCHING (MEGAGRAMS/YEAR)

Pollutant	Added Natural Gas	Removed Distillate	Net Change
TSP	+0.3	-0.2	+0.1
SO_2	+0.2	-3.7	-3.5
NO_x	+7.7	-3.0	+4.7
CO	+2.2	-0.6	+1.6
HC	+0.8	-0.3	+0.5

Assumptions: Sulfur Content of Gas = 0.01 percent
Sulfur Content of Oil = 0.6 percent

Petroleum Refining, Norco, Louisiana

A coal fired cogeneration system utilizing a new 11.1 MW steam turbine (Figure 4-7) is being considered for an existing petroleum refinery in southern Louisiana. Since fuel oil, which is currently used, will be displaced by coal, emissions will be increased. Coal use is estimated at 5,891,430 gigajoules per year (5,584,000 MM Btu per year) replacing residual oil use of 5,216,200 gigajoules per year (4,944,000 MM Btu per year). Since a fuel switch is contemplated at this plant, whether or not a cogeneration system is installed, an emissions increase would still be expected, as shown in Table 4-9.

TABLE 4-8. NET REGIONAL EMISSIONS CHANGES DUE TO COGENERATION AT MEAT PACKING PLANT (MEGAGRAMS/YEAR)

Pollutant	Plant	Utility	Net Change
TSP	+0.1	-7.5	-7.4
SO_2	-3.5	-44.1	-47.6
NO_x	+4.7	-26.1	-21.4
CO	+1.6	-1.5	+0.1
HC	+0.5	-0.5	0.0

Assumptions: Utility Coal Sulfur Content = 0.8 percent, Ash = 6.5 percent
Particulate Removal Efficiency = 96 percent

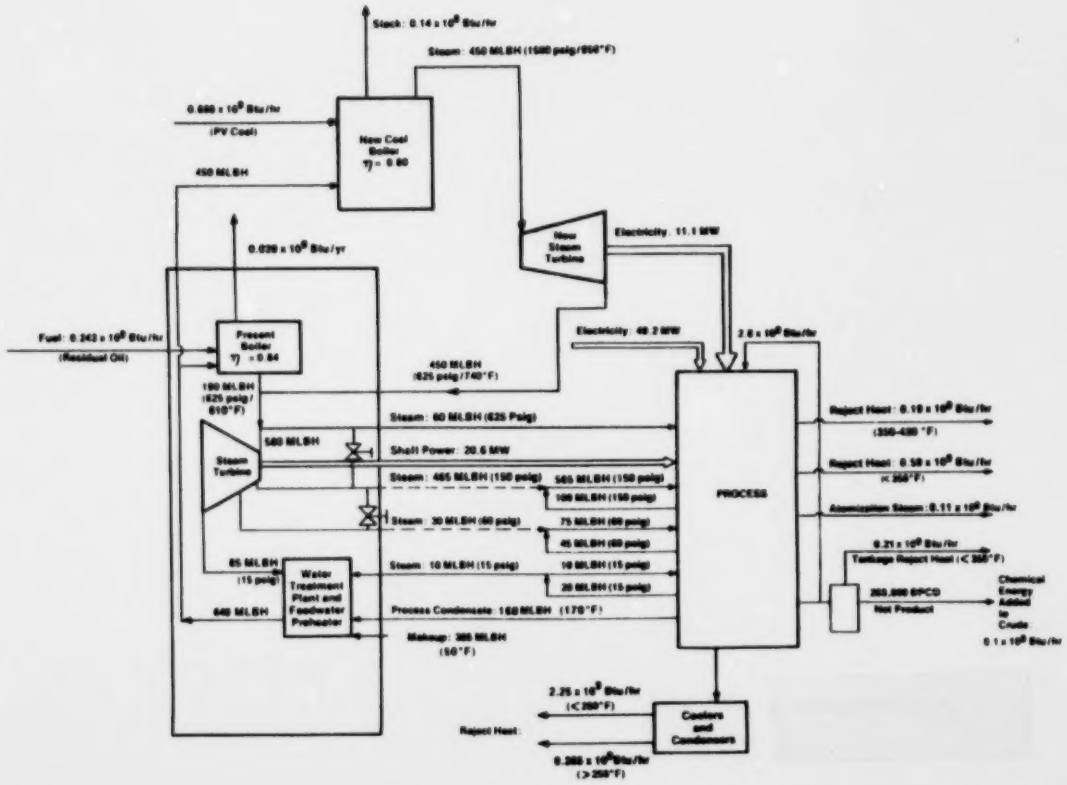

Figure 4-7. Non-site specific Average Large Refinery - PAD 2 Cogeneration Option

Since the heat input of the steam system will be greater than 264 megajoules per hour, the Federal new source performance standards (NSPS) for steam generators will be applicable. The cogeneration system conceptual design incorporated scrubbers and precipitators and emissions estimates assume that the NSPS will be met. Since the type of coal to be burned is unknown, calculations were made for both lignite and bituminous coals. Table 4-9 presents the emission changes due to the new cogeneration system including the reductions attributed to decreased oil use. As shown in the table, the emissions of all pollutants will increase as a result of the fuel switch which accompanies the installation of the cogeneration system, with sulfur dioxide having the greatest net increase.

The refinery's new boiler is large enough to be considered a major stationary source for purposes of both PSD and nonattainment regulations. The refinery is located in the Southern Louisiana - Southeast Texas AQCR which is attaining all of the air quality standards with the exception of photochemical oxidants. (Note, however, that since the relaxing of the oxidant standard in February 1979, some urban areas in the AQCR were reclassified as attainment areas.) Net changes in emissions of particulates, sulfur dioxides and nitrogen oxides at the refinery exceed PSD de minimus levels irrespective of the type of coal burned. Therefore PSD review and BACT will be applicable for these pollutants. The same will be true for carbon monoxide if bituminous coal is burned, since the net change in emissions for this pollutant is projected to exceed 90.7 megagrams (100 tons) per year. Increases in hydrocarbon emissions do not exceed 36 megagrams (40 tons) per year. Therefore, the plant would not have to meet either PSD or non-attainment regulations for this pollutant.

TABLE 4-9. EMISSIONS CHANGES DUE TO NEW BOILER AND FUEL SWITCH AT LARGE REFINERY (MEGAGRAMS/YEAR)

Pollutant	Coal*		Oil**	Net Change	
	Lignite	Bituminous		Lignite	Bituminous
TSP	+ 253	+ 253	- 150	+ 103	+ 103
SO_2	+3,038	+3,038	-1,684	+1,354	+1,354
NO_x	+1,519	+1,772	- 920	+ 599	+ 852
CO	+ 144	+ 239	- 76	+ 68	+ 163
HC	+ 44	+ 36	- 15	+ 29	+ 27

*Emissions from coal fired boilers based on meeting 1979 NSPS.
**Sulfur content of residual oil = 0.7 percent.

The utility energy reduction amounts to 1,062,060 gigajoules per year (1,006,637 MM Btu per year) as a result of the increased efficiency of the cogeneration system. The utility plants in Southern Louisiana burn natural gas primarily, which is supplemented with oil. The utility plant emissions were calculated on the basis of displacing oil and are presented in Table 4-10. Since the utility plants are off-loading oil use, while the cogeneration plant is burning coal, there is a net increase of emissions of all five pollutants. Since there are several utility plants within the AQCR, it is assumed that the net emissions change would occur within the AQCR rather than other parts of Louisiana. The 97 megajoules per year increase of SO_2 emissions represents less than one percent of the total AQCR emissions and is not expected to significantly affect existing air quality levels. Had the utility burned high sulfur coal, the off-loading sulfur dioxide emission from the utility plant would have been significantly higher resulting in an increased benefit of the cogeneration system.

TABLE 4-10. NET REGIONAL EMISSIONS CHANGE DUE TO COGENERATION AT REFINERY (MEGAGRAMS/YEAR)

Pollutant	Refinery Emissions		Utility Emissions*	Net Emissions Change	
	Lignite	Bituminous		Lignite	Bituminous
TSP	+ 103	+ 103	- 2	+ 101	+ 101
SO_2	+1,354	+1,354	- 383	+ 971	+ 971
NO_x	+ 599	+ 852	- 320	+ 279	+ 532
CO	+ 68	+ 163	- 15	+ 53	+ 148
HC	+ 29	+ 21	- 3	+ 26	+ 18

*Fuel Sulfur Content = 0.8 percent, no other emission controls
Particulate Removal Efficiency = 95 percent

Pulp and Paper Plant, Mobile, Alabama

This paper plant currently burns a mixture of natural gas, residual oil and wood in its boilers and intends to switch completely to coal and wood. Whether or not a cogeneration system is installed, the plant still intends to burn solely wood and coal to eliminate its dependence on gas and oil. The current and projected incremental energy use is shown in Table 4-11.

TABLE 4-11. ENERGY USE PATTERN OF PULP AND PAPER PLANT
(ENERGY VALUES IN PETAJOULES/YEAR)

	Present case	New case without Cogeneration	New case with Cogeneration
Gas	3.47	0.00	0.00
Oil	5.41	0.00	0.00
Wood	1.80	9.46	10.03
Coal	0.00	1.67	1.77
Total	10.68	11.13	11.80

A 52.9 MW wood/coal cogeneration system is being considered for the plant and emission estimates have been based on the installation of this system, as well as for wood/coal combustion with and without cogeneration. Figures 4-8 and 4-9 present the base and cogeneration configurations. The emission estimates presented in Table 4-12 indicate increased emissions from the cogeneration system since wood and coal use is replacing oil and gas. The estimates assume that the cogeneration system will meet the NSPS for steam generating units through the use of electrostatic precipitators and a flue gas desulfurization system.

The new boiler burns more than 50 percent wood and therefore is not considered to be a fossil fuel boiler. However, total emissions from the unit will exceed 227 megagrams (250 tons) per year for each criteria pollutant and net emissions at the plant will increase by amounts which exceed de minimus levels. Therefore the plant will have to conform with PSD and non-attainment regulations.

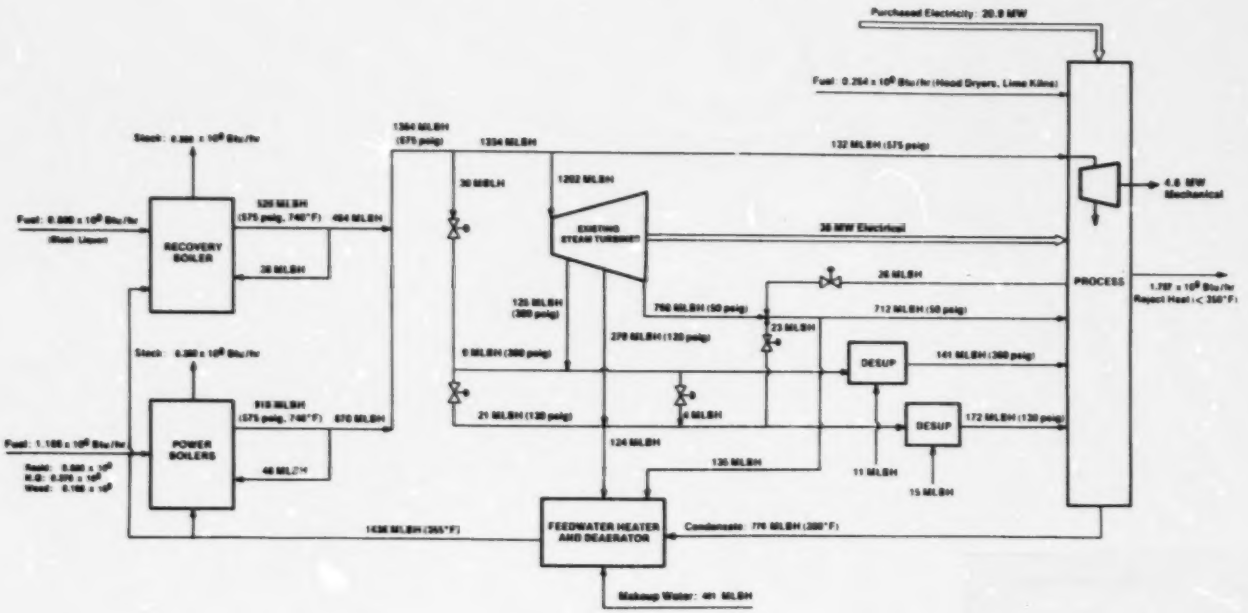

Figure 4-8. Site-specific Integrated Mill - Mobile, Alabama (Reference Case)

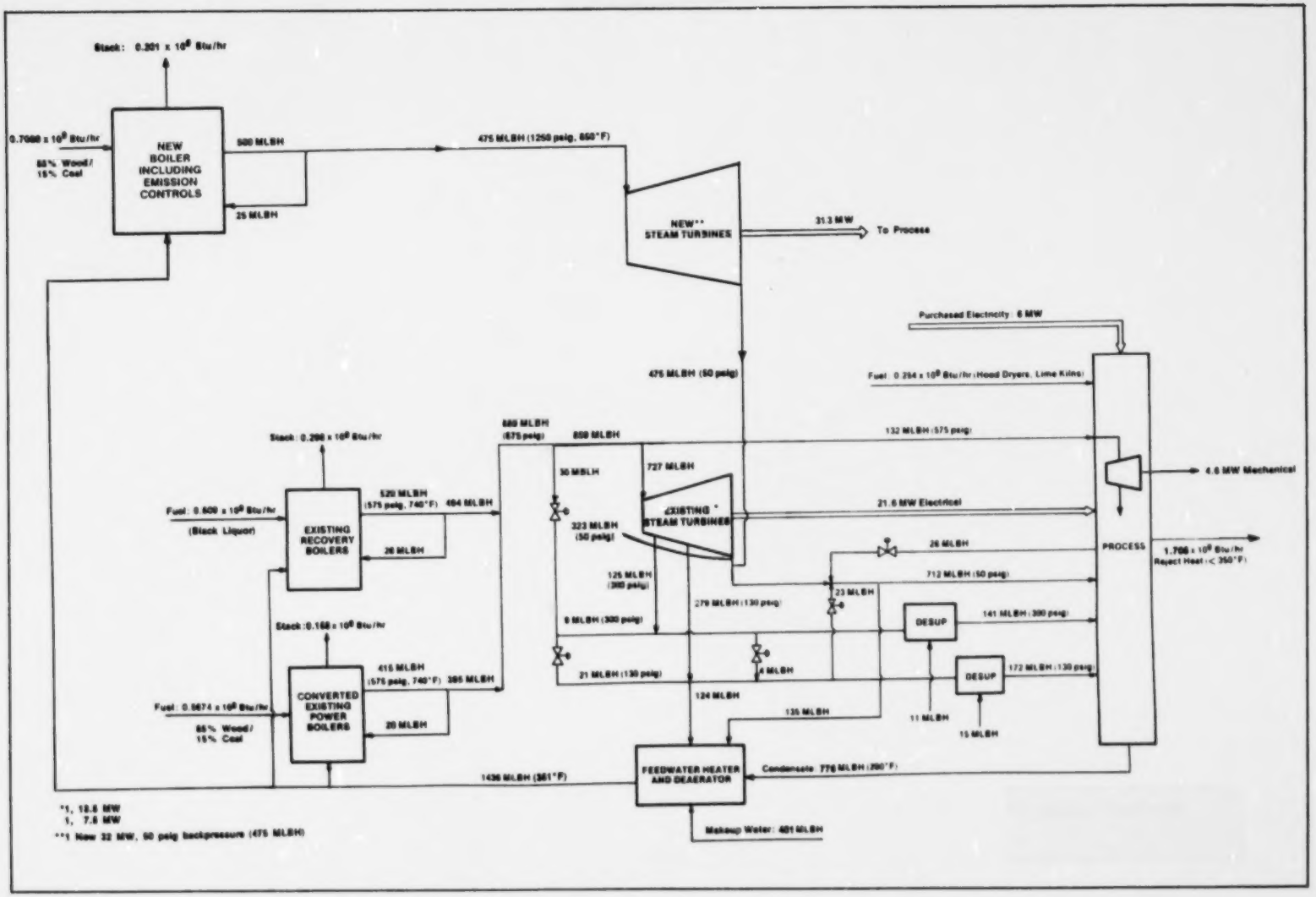

Figure 4-9. Site-specific Integrated Mill - Mobile, Alabama
Cogeneration Option

TABLE 4-12. EMISSIONS CHANGES DUE TO SWITCHING FROM EXISTING FUEL USE TO COGENERATION AND NON-COGENERATION OPTIONS AT PAPER PLANT (MEGAGRAMS/YEAR)

	Existing emissions	New plant without co-generation	New plant with co-generation	Net change between co-generation and non-co-generation options	Net change between co-generation case and existing fuel use
TSP	396	478	500	+ 22	+104
SO_2	1,337	1,472	1,559	+ 87	+222
NO_x	1,523	1,805	1,912	+107	+389
CO	258	844	894	+ 50	+636
HC	175	823	872	+ 49	+697

The paper plant is located in the Mobile - Pensacola - Panama City - Southern Mississippi Interstate AQCR, which is currently attaining air quality standards for all pollutants with the exception of photo-chemical oxidants. Since hydrocarbon emissions are in excess of 36 megagrams per year, emission offsets would normally be required. However, since the majority of hydrocarbon emissions from fuel combustion is usually composed of methane with very little volatile organic compounds which are precursors to photochemical oxidant formation, emission offsets would probably not be required in this case. In addition, PSD review will have to be performed for the other four pollutants and BACT will have to be installed.

Emission estimates were also made for the fuels displaced at the Alabama Power Company plants that might be servicing the paper plant. There are two fossil fuel plants in Mobile County that may be candidates for off-loading, and emission estimates for these plants were based on displacing coal. The total energy savings that can be achieved by the utility plant total almost 1.6 petajoules per year (1,500,000 MM Btu/year) compared with the increased energy use of 1.1 petajoules per year (1,053,000 MM Btu per year) for the cogeneration system. Table 4-13 presents a comparison of the emissions change between the cogeneration and utility plants. The utility emissions reductions are the highest for sulfur dioxide and nitrogen oxides and more than offset the emissions from the cogeneration plant. There is still a net increase in particulate emissions since these would be well controlled by the utility and the fuel has a low ash content. The emissions reductions achievable will increase as the ash content is increased. Carbon monoxide and hydro-carbon emissions also show a net increase due to the higher emission factor for wood combustion.

TABLE 4-13. NET EMISSIONS CHANGE INCLUDING WOOD/COAL COGENERATION CASE AND UTILITY PLANTS (MEGAGRAMS/YEAR)

	Emissions increase from wood/coal with cogeneration	Utility emissions reduced	Net emissions change
TSP	+103	-55	+48
SO_2	+222	-932	-710
NO_x	+389	-520	-131
CO	+636	-29	+607
HC	+697	-9	+688

Assumptions: Utility plant has 98 percent control efficiency for particulates
Sulfur content = 0.85 percent, no emission controls
Ash content = 6 percent

Industrial Park Cogeneration

In this application, a cogeneration plant would supply process steam and electricity to one or more nearby industrial plants. The environmental impacts of this configuration will be similar to in-plant cogeneration using and displacing similar fuels. Since both steam and electricity generating capabilities are utilized, energy efficiencies are similar to in-plant systems. Due to the high generating capacity required in industrial parks, steam turbines will be the predominant system used for the near term and will rely on coal firing due to Fuel Use Act restrictions on oil and gas.

Specific environmental impacts of industrial parks will be highly dependent upon the size of the park, types of industrial plants being served by the cogeneration plant, fuels utilized at each plant, and existing environmental quality at the park site. The industrial park will be subject to greater environmental constraints than would dispersed plants since several potential sources of pollution would be concentrated in a smaller area. Constraints to be considered are air quality, primarily for PSD, water pollution, water resources and thermal effluents. For PSD requirements, each facility emitting greater than 91 megagrams per year (100 tons per year) of any pollutant is subject to PSD review. For particulates and sulfur dioxide, air quality increment levels have been established for each of three area classifications in the U.S. which limits air quality degradation. The establishment of an industrial park with multiple emission sources may have a greater impact on increment levels since the plants will cumulatively impact the local area whereas dispersed plants might not. Due to the potential air

quality impacts of fossil fired industrial parks, the use of nuclear plants in these applications, as well as for district heating, has been analyzed. Advantages of nuclear plants for these applications are: reducing fossil fuel consumption with attendant beneficial impacts on the environment and opening up the supply of fossil fuels to other applications. In the near term, however, industrial parks will be primarily coal fired due to current uncertainties associated with nuclear plants and prohibitions on oil and gas.

Most industrial parks will be established with high generating capacities to provide incentives for each of the industrial partners to tie into the cogeneration system. All of the potential constraints described earlier will impact future industrial park development. An example of the interrelationship between these constraints was evidenced by a recent industrial park cogeneration system planned for a petrochemical complex in Texas City, Texas. The cogeneration plant would generate 567,000 kilograms of steam per hour (1,250,000 pounds per hour) and approximately 150 MW of electricity for three industrial sources. After several years of study, plans for this facility were recently discontinued due to increased costs. Factors cited in this increase included the piping of steam for a distance of two miles for one of the plants which no longer made the system attractive. Although no adverse air quality impacts were projected on the basis of air quality modeling, other environmental constraints such as lengthy permitting processes were cited by the developers as adding to the cost of the facility. An additional factor in the plant's cancellation was the increased availability of natural gas for the three plants.

A reference case was developed for a cogeneration plant in an industrial park to assess the environmental impacts of this configuration. The results of this analysis cannot necessarily be extrapolated to other industrial parks since it is based on a specific type of fuel use for the cogeneration plant, and fuel displacements specific for the two industrial plants, one of which is a refinery and the second a synthetic chemicals plant. Due to the varying types of fuels, combustion devices, and process requirements that can occur, as well as site characteristics, a typical industrial park cannot be developed to extrapolate data to another application. The reference case for this example was based on a cogeneration plant producing 200 MW of electricity and exported steam at 670 K (750^{0}F), 4.5 megapascals (650 psig), and meeting all current environmental requirements. The combustion device is a steam turbine firing coal of 2.9 percent sulfur and 11.5 percent ash. The plant will displace 128 petajoules per year (121 x 10^{12} Btu per year) of bituminous coal being utilized at a nearby facility and 72 petajoules per year of oil at another facility.

The pollution residuals from these plants are shown in Table 4-14. The cogeneration plant will be responsible for significant levels of sulfur dioxide, nitrogen oxides and solid wastes, but will still contribute to a net reduction in air pollutants.

The air pollutant emissions from the cogeneration plant are offset by the reduced fuel use at the two industrial plants. These reductions are possible since coal is displacing coal and oil. If oil and gas were displaced by coal, then little if any emissions reductions would be achieved.

TABLE 4-14. POLLUTANT RESIDUALS CHANGE DUE TO IMPLEMENTING COGENERATION AT INDUSTRIAL PARK

	Air Pollutants (Megagrams/Year)			Water Pollutants (Megagrams/Year)	Solid Waste (Gigagrams/Year)
	TSP	SO_2	NO_x	Suspended Solids	
Cogeneration Plant	+2,739	+32,868	+19,176	+685	+354
Industrial Plant A (oil)	-2,071	-21,678	- 13,808	-49	-0-
Industrial Plant B (coal)	-2,061	-15,194	-12,409	-217	-209
Net Change	-1,393	- 4,004	-7,041	+419	+145

In order for a coal/steam turbine to meet the NSPS for sulfur dioxide in an utility application, a flue gas desulfurization (FGD) system is required. Due to the large amounts of solid and liquid wastes associated with these systems, the waste impacts are greater than for either gas or oil fired systems and usually result in a negative impact, since oil and gas fired systems do not produce equivalent amounts of waste for the energy produced. In the reference case, there is a net reduction in the solid wastes produced since Plant B, which is also a coal fired system, will be reducing fuel use. Significant increases in the amounts of solid waste generated also occur.

The waste heat normally rejected in a conventional steam turbine system is now being recovered in the cogeneration plant, while at the two industrial plants it is reduced as the result of decreased fuel consumption. These savings in rejected heat would be accomplished for oil and gas fired industrial plants as well as coal fired facilities providing an additional incentive for cogeneration.

SPECIFIC REGIONAL ANALYSIS OF COGENERATION

Cogeneration development will be influenced significantly by the projected industrial development in a region, types of fuel available and projected fuel prices. Among the several studies assessing the potential for cogeneration, regional assessments have also been made as referenced earlier. In addition to the Tennessee Valley Authority and New England studies, the Public Service Electric and Gas Company (PSE&G) of New Jersey also is assessing the increased use of cogeneration in its service area.[11] These studies are summarized in this report and each presents a specific rationale for interest in cogeneration. The Tennessee Valley Authority service area will be experiencing increased industrial growth over the next 20 years and is assessing the use of emerging technologies and alternate fuels in existing technologies for cogeneration applications. The New England area is characterized by a limited amount of heavy industry and a high dependence upon imported oil. The Public Service Electric and Gas Company has over two decades of experience in cogeneration upon which to base its future plans for expanding the use of this technology.

Tennessee Valley Authority

The TVA has conducted a preliminary assessment of cogeneration potential at existing and future utility plants, industrial plants, and energy parks. They have concluded that there is very little, if any, potential at existing utility plants. The present TVA power generating system consists of 12 coal fired steam generating plants with a total of 66 units. In addition, there is one nuclear plant at Browns Ferry, Alabama, which consists of three boiling water reactors. None of these units at this time have the capability to cogenerate, nor are there any plans to develop their capability. An indepth analysis by TVA of their existing units indicated that developing cogeneration capability was not feasible. The TVA plants were not designed with excess steam capacity, therefore the supply of steam through a topping turbine cannot be assured. Another option considered was to increase the firing rate and heat absorption area in the boilers, however most of the TVA boilers have marginally sized furnaces which limits this option. Reducing generator output to extract steam from the turbine cycle also would not be acceptable due to reduced electrical output. The addition of cogenerating units to existing plants was evaluated, however the area available in the vicinity of these plants is limited. The siting of additional units requires space for flue gas cleaning equipment, sludge disposal areas, and water treatment facilities, as well as space for the units themselves.

Another option considered was the conversion of combustion turbines to cogenerating units with waste heat boilers. There were 48 combustion turbines in operation during 1977 with fuel oil consumption at 0.73 cubic megameters (193 million gallons). The efficiency of these units can be increased, however a preliminary analysis indicates that the option may not be cost-effective.

Since the use of existing utility plants for cogeneration has been found to offer little potential, the emphasis will be placed on future plants, especially those using combined cycles. The options that will be evaluated by TVA for future plants includes the feasibility for cogeneration at all coal fired plants larger than 200 MW_e, the installation of small fossil fuel plants near industrial plants requiring process steam, and the use of waste thermal energy at nuclear power plants.

An estimate of both potential cogeneration capacity and installed capacity has been made for the 1989 to 1998 timeframe as there is expected to be little potential before that period. There are three scenarios based on low, medium, and high penetration levels with the range of cogeneration capacity for a power plant being 200 to 800 MW_e. Total installed capacity for utility and industrial sources would range from 530 MW_e to 1865 MW_e during this period, and is equivalent to an oil savings of approximately 0.29 to 0.99 cubic megameters per year (1.8 to 6.2 million barrels per year). This 1865 MW_e represents approximately 16 percent of the theoretical cogeneration potential. An estimate of air pollutant emissions reduction has been made on the basis of coal use equal to the oil savings and is summarized in Table 4-15. These emissions reductions are not site specific but could occur anywhere in the TVA region.

An analysis of industrial plants in the TVA region indicate that there are six industrial plants currently using cogeneration systems with total electrical output from these plants amounting to 120 MW_e. This represents approximately 0.4 percent of the TVA generating capacity. It is estimated that another 100 to 150 MW_e of cogeneration potential could be developed in the pulp and paper industries. Of the facilities in this classification, it was estimated that 50 would have peak steam requirements greater than 22,680 kilograms per year (50,000 pounds per hour) which is considered to be the minimum requirement in order to be economically feasible for cogeneration. A few customers in the food, textiles, rubber products and primary metals industries also use steam meeting the 22,680 kilograms per hour requirement and could also be cogeneration candidates. Industrial growth in the service area will include industries with potential for in-plant cogeneration and TVA will encourage these industries to develop the potential. It is estimated that by 1998, cogeneration could account for approximately 300 MW_e of power generation in new industries. The near term potential for electric generation through in-plant cogeneration is approximately 110 MW_e by 1983 and with the addition of project in other industries may reach 355 MW_e.

The potential constraints to the development of cogeneration for industrial sources includes future industrial growth, reliability and availability of fuel or waste heat, and institutional and environmental factors. The reliability of fuel is especially important when waste materials are used. The TVA has examined the use of both wood waste and municipal waste for use in cogeneration systems with the latter being the most promising of the two. It is estimated that full development of industrial cogeneration potential from refuse incineration would offer a capacity savings of 446 MW_e by 1998, with TVA's goal at developing 20 percent of this potential. Since the composition of solid waste can

TABLE 4-15. EMISSIONS REDUCTIONS BASED ON ENERGY SAVINGS FROM COGENERATION DISPLACING UTILITY PLANT COAL USE IN THE TVA REGION*

Coal Savings**		Emissions Reduction (Megagrams/Year)		
Megagrams/Year	(Petajoules/Year)	TSP	SO_2	NO_x
4.9×10^5	11.4	486	7,015	3,820
1.0×10^6	22.8	970	14,025	7,635
1.7×10^6	39.3	1,675	23,375	13,155

*Based on coal use at Widows Creek Station
Coal characteristics: Sulfur = 3.7 percent
Ash = 25 Percent
Heat content = 23.2 megajoules/kilogram (10,000 Btu/pound)
Control efficiencies = 80% for SO_2, 99.5% for TSP

**Based on range of equivalent oil savings of 0.29-0.99 megameters^3/year ($1.8\text{-}6.2 \times 10^6$ barrels/year).

vary by community or industrial source, its heat value and potential air pollutant emissions can also vary, therefore the development of a waste-as-fuel system for cogeneration must be carefully analyzed before an investment of capital is made for the system.

In addition to utility and industrial plants serving as candidates for cogeneration, TVA is examining cogeneration at industrial complexes and energy parks. At the present time, there are several industrial complexes in the TVA service area that are potential cogeneration participants. There are two purposes in cogenerating power and heat within the TVA jurisdiction: 1) conserving prime fuels and natural resources, and 2) to minimize expansion programs needed to satisfy the projected baseload capacity required over the next 20 years.

A prime location considered for an industrial complex is Calvert City, Kentucky which has four plants all within two miles of each other and three of them occupying contiguous plant sites. The cogeneration potential is estimated to be 10 to 20 MW_e based on discussions with the industries. A coal based cogenerating system with municipal refuse as a supplement for about 10 percent of the heat input has been investigated. Calvert City is located in the Paducah-Cairo Interstate Air Quality Control Region (AQCR) which is currently classified as a non-attainment area for particulate matter. The attainment of the air quality standard must be demonstrated by December 31, 1982 in accordance with Clean Air Act requirements, therefore the non-attainment status may no longer impact the development of the cogeneration system since it would probably not be developed before 1982 anyway. However, these areas may be meeting the standards just barely, and in order to stay within the standards, new sources may have to obtain emission offsets, or utilize pollution controls that are more efficient than best available control technology (BACT).

Other industrial concentrations exist at Decatur, Alabama and New Johnsonville, Tennessee, where large, directly served industries are close to large, distributor-served plants requiring steam. The co-generation potential at these sites along with other smaller scale sites in Tennessee and Mississippi total approximately 10 to 40 MW_e.

Decatur, Alabama is located in the Tennessee River Valley - Cumberland Mountains Interstate AQCR. Morgan County, in which Decatur is located, is a non-attainment area for photochemical oxidants and portions of the county are non-attainment for the secondary particulate standard. In addition, the Bankhead National Forest, a PSD Class 1 area, is located within 50 kilometers of Decatur. This situation will require that a detailed air quality modeling analysis be done to determine if the park will be adversely affected. The New Johnsonville area is classified non-attainment for the primary sulfur dioxide standard, which may also be impacted by a fossil fuel fired system.

Cogeneration at future energy parks was also assessed by TVA. A concept of tristate energy parks comprising the states of Alabama, Kentucky and Tennessee has been studied. This assessment included both topping and bottoming cycles with different types of prime movers, potential for cogeneration with solar energy, and the use of wood and municipal wastes as fuel sources. A total potential cogeneration capacity of 5400 MW from new large industrial/ energy parks in the tristate region is estimated by 1990, which would result in freeing approximately 3100 MW of the TVA load. The anticipated efficiency of the cogeneration plants in future energy parks is estimated to range from 55 to 75 percent.

A total of 13 potential energy park sites have been examined on the basis of selection criteria developed by TVA. Although the types of industries in these parks would vary, coal would supply approximately 97 percent of the energy demand, with the remainder made up by municipal solid waste. Coal quality in the tristate region ranges from 1.8 to 4.3 percent sulfur, and 8.0 to 17.6 percent ash content. The use of coal for the energy parks has raised some generic environmental concerns for the TVA region as follows:

- Coal combustion is a major source of sulfur and nitrogen dioxide emissions in the TVA region and a significant source of particulate matter. Table 4-16 presents an example for the state of Tennessee indicating the percentages of these pollutants contributed by stationary fuel combustion sources. The ambient levels of these pollutants are highest in the areas adjacent to these sources. The addition of new fuel combustion sources such as energy parks near these plants may potentially aggravate the existing air quality.

- Water resources and quality may limit the development of some of the energy parks since low flow periods have been experienced in some of the river sources, and water quality has been degraded from existing sources.

Although actual impacts cannot be determined until a site specific analysis is conducted after sites have been selected and operation parameters of the cogeneration facilities are drawn, a preliminary environmental assessment has been made for the 13 candidate sites. This assessment was based on the expected residuals produced by the cogeneration plant assumed for each site. Example sites for each state were selected and analyzed for the type of cogeneration system, energy demand, capacity and heat rate. This information is summarized in Table 4-17.

Several newer technologies have been examined by TVA for cogeneration systems and include fluidized bed combustion, both pressurized and atmospheric, fuel cells, magnetohydrodynamics, energy storage and solar power. The most likely candidate for near term cogeneration is atmospheric fluidized bed combustion (AFBC) due to the following factors:

- The technology has been proven more successful than the other technologies.

TABLE 4-16. EMISSIONS (MEGAGRAMS/YEAR) CONTRIBUTED BY FUEL COMBUSTION SOURCES IN TENNESSEE*

	Total State Point Source Emissions	Utility Coal Use Emissions	Industrial Coal Use Emissions	Total Utility and Industrial Emissions**	
Particulates	131,230	54,750	7,810	62,565	(48%)
Sulfur Dioxide	1,126,250	980,960	61,550	1,042,500	(93%)
Nitrogen Dioxide	280,100	204,720	19,350	224,075	(80%)

*Source: Environmental Protection Agency; 1976 National Emissions Report, EPA-450/4-79-019, August 1979.

**Numbers in parenthesis signifies the percentage of the state-wide emissions due to utility and industrial sources.

TABLE 4-17. SUMMARY OF TRISTATE COGENERATING POWER PLANTS

Location	Energy Source	Cogeneration Capacity		Process Requirements		Heat Rate
		Elec (MW)	Therm (TJoule/Hr)	Power (MW)	Therm (TJoule/Hr)	MJoule/kWh)
Finley Island, Alabama	Coal/ Wood	640	9.6	490	2.4	6.3
Gibraltar, Kentucky	Syngas/ Methanol	4,330	44.4	1,455	41.2	5.6
Trotter's Landing, Tennessee	Wood/ SNG	290	2.3	280	1.8	5.6
Fork of the River, Tennessee	SNG	95	0.8	42	0.7	5.4

Source: TVA Report, June 1979.

- Air pollution emission can be controlled without the use of low sulfur coal.

- Integrated into an existing steam plant, AFBC would minimize the impact on system operation.

- Technology is adaptable to either energy park or central plant sized installations aiding in site selection.

The new technologies are not expected to contribute more than 20 to 50 MW of cogeneration capacity at any one time over the next 20 years in the service area primarily due to the need for a highly dependable steam supply from cogeneration systems. However, as the reliability of steam supply improves, the emerging technologies could raise the interest in cogeneration by industrial plants.

Cogeneration Potential in New England

A recent study was conducted to determine the benefits of cogeneration to the New England area, with emphasis on Massachusetts.[5] This area has a heavy dependence upon fuel oil, most of which is imported, accounting for approximately 80 percent of all the energy used. Energy costs are among the highest in the nation in this region with electricity rates for Boston Edison's residential customers averaging 6.39 cents per kWh during 1980. The near term (mid-1980) potential for cogeneration was found to be 644 MW in Massachusetts and 1683 MW in New England. If all of the cogeneration units used oil, 0.6 and 1.6 million cubic meters (162 and 423 million gallons) of oil per year could be saved in Massachusetts and New England, respectively, based on the fuel that would be displaced at the utilities.

The energy use pattern in New England is different than the rest of the country due to the limited amount of heavy industry in this region. Fuel use by industries in New England accounts for approximately half of that used by utilities. This relationship results in a low potential for industrial cogeneration in these areas. Cogeneration at commercial sites presents a logical alternative due to two factors: (1) in Massachusetts, the commercial sector uses more than five times as much oil as the industrial sector and (2) most commercial sites have a lower heat temperature requirement.

The estimated 1683 MW of near term cogeneration potential for New England represents approximately 24 percent of the planned new capacity in the New England Power Pool over the next 10 years. The 644 MW of cogeneration in Massachusetts is about 20 percent of planned utility expansion over the same time period. Based on the amount of fuel oil consumed by the cogeneration systems and the amount displaced at the utility, estimates of air pollutant emissions have been made for both systems. Because most commercial establishments are not permitted emission sources, the reduction of their emissions is not accounted for.

The data presented in Table 4-18 indicates that the emissions increase from cogeneration systems will be significant for both sulfur and nitrogen oxides which may cause localized problems. However, region-wide emissions will decrease. The entire state of Massachusetts was attaining the standards for these two pollutants as of December 1979, therefore non-attainment area regulations would not impact the cogeneration systems. Several metropolitan areas in the state, as well as the city of Boston, are non-attainment areas for carbon monoxide primarily due to motor vehicles. Although a total of 250 megagrams (280 tons) of carbon monoxide emissions have been estimated for the entire state from cogeneration systems, unless these occurred in one of the metropolitan areas, obtaining permits for the systems would not be constrained. The requirements for Prevention of Significant Deterioration (PSD) will have to be met for any source emitting 91 megagrams (100 tons) per year of any pollutant.

The utility emissions reductions, also shown in Table 4-18, are significantly higher than the emissions increase from cogeneration, resulting in substantial reductions in both Massachusetts and New England. Sulfur dioxide emissions in New England would decrease by over 20,900 megagrams (23,000 tons) and nitrogen oxides by about 30,600 megagrams (34,000 tons) due to the amount of residual oil displaced at the utilities. For each pollutant, the amount of emissions reduced at the utility plant is higher than that increased by the cogeneration system. If both the cogenerator and the utility plant are in close proximity, then no adverse air quality impacts would be expected to occur. However, if the cogenerating system is in an urban area and the off-loaded plant is in either a rural area or in another air quality control region, then localized air quality impacts may occur. The emissions increase would be significant as there would be nearly 3,600 additional megagrams of sulfur dioxide emissions in Massachusetts alone, most of which would be in urban areas. Based on current emission levels, this represents approximately 1.3 percent of the total sulfur dioxide emissions in the state. The actual air quality impact can only be determined by considering the location of the cogeneration systems, types of emission controls, and background pollutant levels. These emissions estimates will vary if alternate fuels such as coal, municipal solid waste or wood waste are used.

Cogeneration Evaluation in the Public Service Electric and Gas Company of New Jersey (PSE&G)

An assessment of cogeneration potential in the PSE&G electrical territory was conducted using a "total system" approach which examined the total costs to the utility company and its customers.[11] A separate analysis was conducted of two scenarios: (1) PSE&G system expansion based on the displacement of planned nuclear units, and (2) the currently planned PSE&G system expansion. In addition, site specific studies of 18 customers were conducted.

TABLE 4-18. NET EMISSIONS CHANGE FROM COGENERATION AND UTILITY SYSTEMS IN NEW ENGLAND REGION (MEGAGRAMS/YEAR)

	Emissions From Cogeneration System*		Emission Reduction at Utility**		Net Emissions Reduction	
	Mass.	New England	Mass.	New England	Mass.	New England
TSP	5.0	12.8	22.2	57.2	17.2	44.4
SO_2	3,578.0	9,042.0	11,615.0	29,927.0	8,036.0	20,885.0
NO_x	1,109.0	2,800.0	12,946.0	33,359.0	11,838.0	30,557.0
CO	252.0	636.0	616.0	1,589.0	365.0	952.0
HC	50.0	127.0	123.0	318.0	73.0	190.0

*Represents Emissions Increase - Assume Distillate Oil Use; Sulfur Content = 0.5%. Particulate Control Efficiency = 95%.

**Represents Emissions Decrease Due to Displaced Fuel Use - Assume Residual Oil Use; Sulfur Content + 0.6%, Particulate Control Efficiency = 95%.

The use of cogeneration has been practiced by PSE&G since 1957 in supplying both electricity and process steam to the Exxon Bayway refinery. A 450 MW power plant was originally installed at the Linden, New Jersey generating station with the capability of supplying the refinery with a maximum steam demand of 700,000 kilograms per hour (1,550,000 pounds per hour) in 1972. An additional 80 MW unit was placed in service at Linden to increase the steam supply to 1,100,000 kilograms per hour (2,400,000 pounds per hour). It is estimated that this cogeneration system operates at an overall efficiency of 54 percent compared with a conventional electric efficiency of less than 40 percent. In addition to supplying the refinery steam requirements, PSE&G uses some of the steam from its turbines for its synthetic natural gas plant located next to the Linden generating station with a capacity of 3.5 million cubic meters (125 million cubic feet) per day.

In order to determine the potential for cogeneration, PSE&G developed a listing of all industrial customers estimated to save 2.45 megawatts (250 boiler horsepower) or more of process steam capacity, of which approximately 270 customers were found. A follow-up survey of the 78 larger customers was made to determine future steam needs and boiler age. A detailed study was then conducted of the 18 largest customers who qualified with a minimum steam use of 45,000 kilograms per hour (100,000 pounds per hour) for 5000 hours per year or more. Based on the steam demand profiles of the 18 customers, it was found that there was a theoretical combined cogeneration power potential of 430 MW, which would serve as base load.

The PSE&G study obtained the following results.

a. System Expansion

The installation of combustion turbine cogeneration in incremental stages over a three year period would result in the postponement of planned nuclear units at an economic penalty of approximately $400 million in additional revenue requirements.

An estimated 6.8 million additional cubic meters (43 million barrels) of distillate oil will be consumed in the PSE&G territory between 1981 and 2000 if the cogeneration systems were installed in place of the nuclear units. Cogeneration would actually increase oil usage by 19 million cubic meters (117 million barrels), however a savings of 0.8 million cubic meters (5 million barrels) for PSE&G generating units and 11 million cubic meters (69 million barrels) of oil could be achieved by the Pennsylvania-New Jersey-Maryland (PJM) interconnection, resulting in a net increase of 6.8 million cubic meters (43 million barrels) of oil.

b. Site Specific Analysis

The analysis of each of the 18 customers indicated that 12 of the customers may be able to install a total of 300 MW of cogenerated power. Energy costs to the customers range from a savings of six percent for those facilities not requiring on-site back-up to a penalty of three percent based on a 25 year recovery period for the cogeneration equipment.

c. Integrated Community Energy System

An evaluation was also performed of the application of the grid connected Integrated Community Energy System (ICES) concept for supplying electric and thermal energy to a group of office and apartment buildings in Trenton. Based on the review of generation/heat recovery technologies, a combustion turbine/waste heat boiler concept was selected. Four turbines, each with a 2 to 5 MW capacity, supply a heat recovery boiler with steam capacity of 6,400 kilograms per hour (14,200 pounds per hour) at 1035 kilopascals (150 psig). The low temperature recovery stages of the heat recovery boilers will also generate a total of 1.8 cubic meters (480 gallons) per minute of 430^{o}K (320^{o}F) water as additional heating supply.

The results of the preliminary analysis indicated that the Trenton ICES project appears to be technically feasible and may be economically competitive with competitive means for heating and cooling. The plant will consume approximately four to nine percent more fuel oil compared to a conventional oil fired system, but will provide an overall reduction in consumption of all fuel types of 32 to 43 percent. The amount of energy saved is the equivalent of 23,293 barrels of oil although the fuel actually displaced at the utility would probably be coal, amounting to approximately 4,800 megagrams (5,376 tons). Assuming an average sulfur content of 2 to 3 percent and ash of 11 percent, the air pollutant emissions reduction would amount of 215 megagrams (235 tons) of sulfur dioxide and 430 megagrams (473 tons) of particulate matter.

SECTION 5

FUTURE ENVIRONMENTAL CONSIDERATIONS

ENVIRONMENTAL ISSUES AND RESEARCH NEEDS REQUIRING FURTHER ANALYSIS

The increased interest in cogeneration in the U.S. has raised several issues dealing with the environmental aspect of this technology which will need to be resolved before it can gain widespread acceptance and be developed in an environmentally acceptable manner. These issues have been raised by both current users of cogeneration and those that have expressed interest in utilizing the technology in utility and industrial applications. It should be noted that the following issues are not necessarily regarded as constraints but expressed as concerns which need to be researched.

Environmental Issues

Regional Versus Site-Specific Emission Changes. The cogeneration system's emissions would, theoretically, be more than offset by reductions of emissions at the utility company servicing the cogeneration plant. However, as shown in previous analyses, it is difficult to determine which plant in the utility grid would be off-loaded due to cogeneration. Also, there is a problem in assuring that the utility emission reductions will be permanent. In fact, as demand grows in the utility service area, these reductions are likely to disappear.

In some cases, the utility plant may be several hundred miles away and although the overall emissions levels in its surrounding area would be reduced, it would not have any impact on the cogeneration plant. The utility companies usually reduce power generation at those plants that have the lowest capacity factors and highest operating costs and, therefore, could be anywhere in the utility grid network. This is another factor which will probably make the assignment of emission reductions to a cogeneration facility difficult.

Use of Diesels and Gas Turbines in Urban Areas. There are two major problems facing the increased use of diesel and gas turbine cogeneration systems in urban areas: air pollution emissions and ambient noise impacts. Small power plants (less than 10 MW) will consist primarily of gas turbines and diesel engine powered systems. The air pollutants of concern are nitrogen oxides from both systems and particulate emissions from diesel engines. Nitrogen oxides are produced by the high combustion temperatures and fuel based nitrogen content. The use of either system in urban areas aggravates the nitrogen oxide levels created from motor vehicle emissions which account for approximately 30

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percent of the national total. Due to decreased dispersion of pollutants in urban areas due to canyon effects from tall buildings as opposed to power plants in remote areas, urban area air quality to which the majority of the population is exposed may be adversely impacted.

Diesel engines burning distillate oil emit approximately seven times as much particulates as a conventional boiler. These particulates are composed primarily of carbon but a large portion of the particles may consist of condensed-extractable organics on carbonaceous matter, including compounds with three to six benzene rings. Some of these polycyclic aromatic hydrocarbons are known to be carcinogenic but little is known of the remainder. Once the particulate matter is emitted to the atmosphere, it can stay suspended for several weeks. The smaller particulates (less than 15 microns) can be inhaled deep into the respiratory tract doing the most damage. The increase of diesel cogeneration coupled with diesel vehicles could result in potential adverse health impacts requiring additional research in this area as well as control techniques.

The second area of concern with these systems is in noise generation from engine driven electric generators placed on-site. The noise emissions and vibration for each type of on-site installation are site specific depending upon the output of the electric generator, type of noise repression equipment, and acoustic environment surrounding the equipment. It is essential that the generating equipment be properly installed to isolate low frequency vibration which can then be controlled through suppression devices.

Environmental Research Needs

The following areas should be given high priority for future research to ensure that cogeneration is developed in an environmentally acceptable manner: (1) analysis of potential environmental problems from new energy technologies, and (2) assessment of the potential environmental issues dealing with district heating cogeneration systems.

Impact of New Technologies

The new energy technologies being developed by the Department of Energy and private industry will provide new energy supplies as well as more efficient methods of energy utilization and power production. New energy supplies will result primarily from the production of synthetic fuels consisting of coal-derived liquids and gases, shale oil, and enhanced oil and gas recovery of existing supplies. First generation coal conversion processes will be producing boiler fuels and petrochemical feedstocks. Although these fuels will be lower in sulfur and ash content than the parent coal, they may contain other contaminants of potential carcinogenicity which are analagous to some petroleum products. The same is true of oil shale products, although they will be used primarily for transportation sources with some fuels applicable to diesel engines. Both the EPA and DOE are supporting research efforts to assess the environmental and health issues of synthetic fuels utilization.

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In the area of power generation, several technologies could be used in cogeneration systems such as fluidized beds, fuel cells, and Stirling engines. Each of these technologies have specific pollution characteristics although they are each expected to be less polluting than conventional systems.

Environmental Issues for District Heating

In a district heating application, a cogeneration system supplies steam or hot water to residential and commercial buildings, thereby replacing space heating fuels normally used. The advantages of this system from an environmental perspective is that most of the pollutants are concentrated at a central plant where they can be better controlled rather than being emitted from individual heating units. There are few, if any, pollution controls used in residential and commercial heating systems which are fired by gas or oil. Approximately 55 percent of the residential heating equipment in the U.S. is fired by gas and 26 percent by fuel oil, based on the 1970 census. District heating offers an opportunity to save these scarcer fuels in those areas where it can be implemented. Criteria for district heating feasibility includes a high number of degree days, large potential load and the utilization of either coal or oil at the supplier power plant. In addition, there has to be a strong interest on the part of the utility company to provide steam or hot water as a byproduct. Consumer acceptance of the system over conventional methods must also be considered as a potential factor in its development.

Interest in district heating has increased significantly over the last few years as the potential energy savings afforded by this system is more attractive. The DOE is sponsoring several programs to assess the various economic, regulatory, technical, and institutional constraints in developing district heating systems. In addition, an interagency task force has been formed which includes EPA to identify and help to mitigate the potential constraints on district heating. The renewed interest requires that EPA assures the environmental acceptability of this technology as it evolves. Although the future market penetration of district heating cannot be accurately assessed, estimated of 1 to 2 exajoules (1 to 2 quads) by the year 2000 have been made.

In the near term, district heating plants will be coal-fired steam turbines with some of the emerging technologies having potential for use over the long term. Since the heating plant will be displacing numerous dispersed systems, fuel use at the plant will be significantly greater than if the plant was solely producing electricity. The environmental impacts of district heating will be dependent to a large extent on the types of fuels being replaced, the distance between the generating plants and the end users and existing environmental quality. Since fuel use and air pollution emissions would be higher on-site, greater local air quality impacts could occur even though fuel use is being displaced at the residential sources. This would be most evident in those cases where a coal fired district heating plant would replace natural gas use which has minor environmental impacts. Current Federal and state air pollution regulations do not consider these offsets; however, for

district heating systems to be widely acceptable, considerations should be made for the offsets obtained in the urban areas and an assessment made of resultant air quality levels through dispersion modeling.

The relationship between emissions and air quality needs to be considered for district heating applications since in many cases the heating plant will be displacing clean fuels in residential units with coal or residual oil. Two recent air quality studies, which are still very preliminary, have been conducted and indicate that on-site emissions increase although air quality levels show improvement. The pollutant emissions which increase are sulfur dioxide, and suspended particulates resulting from increased coal combustion at existing facilities which were retrofitted to cogenerate. Ground level air quality improved in the residential areas as a result of the reduced fuel use. The air quality analyses to date have only considered the impacts on the annual standard, whereas the shorter term standards may be more adversely impacted by the increased emissions. The impacts on regional air quality due to pollutant transport from increased emissions also need to be considered.

The Oak Ridge National Laboratory is currently performing a multi-year assessment of a district heating system for the Minneapolis-St. Paul Metropolitan area.[12] Two design scenarios have been selected for this study: The first restricts district heating to the downtown industrial and to nearby residential buildings. The second also covers medium-density residential districts with one or two family houses outside the central part of the city. Under the first scenario, energy savings equivalent to 7.8 million cubic meters (49 million barrels) could be achieved over a 20 year period, and 9.7 million cubic meters (61 million barrels) under the second scenario. With the increased coal consumption at the district heating power plants, the net fuel savings are approximately 4.9 and 6.2 million cubic meters (31 and 39 million barrels) of oil, respectively.

Environmental analysis of developing the smaller of these two proposed district heating systems is being performed by EPA and DOE. DOE has completed an analysis of the sulfur dioxide emissions and air quality changes which would be expected to occur if this district heating system was developed by 1987.[13] Table 5-2 shows the estimated emission changes for three different scenarios. In Configuration 1 a 190 MW(e)/335MW(t) coal burning, cogenerating power plant is built inside the study area to supply the district heating system. In Configuration 2 the same plant is built outside the study area. In Configuration 3 a larger plant is built outside the study area. This plant is large enough so that existing power plants consume fuel at the same rate as they did before being retrofitted. Hence, no emissions increases occur in Configuration 3 in the study area.

In all three cases there will be a net increase in emissions of sulfur dioxide from tall utility stacks as a result of gas and oil being replaced by coal. Despite the increase in emissions, air quality benefits will occur. Modeling of ground level sulfur dioxide concentrations in the study area shows a 10 to 15 percent decrease if district heating

TABLE 5-1. EFFECTS OF DISTRICT HEATING ON ANNUAL AVERAGE SO_2 EMISSIONS (GRAMS/SEC) IN MINNEAPOLIS-ST. PAUL[a]

	Baseline (1976)	Projected (1987)			
		Without cogeneration	With cogeneration[b] by configuration		
			1	2	3
Point source not including power plants	1080	1265	1139	1139	1139
Existing and retrofitted power plants inside study area	2062	2062	2173	2173	2062
Existing power plants outside study area	4035	5085	5085	5085	5085
Additional cogeneration unit inside study area	0	0	223	0	0
Additional cogeneration unit	0	0	0	223	430
Heat-only boilers[c]	0	0	57	57	57
Area sources	110	343	306	306	306
Total inside study area	3252	3670	3898	3675	3564
% change in 1987 resulting from cogeneration			6.2	0.1	-2.9
Overall total	7287	8755	8983	8983	9079
% change in 1987 resulting from cogeneration			2.6	2.6	3.3

[a] Adapted from Table 2 in Reference 13.
[b] See text for definition of configurations.
[c] Heat-only boilers are assumed to be oil-fired. Natural gas can be used as the fuel, which would reduce the SO_2 emissions from these sources to a negligible value.

is implemented.[13] This is because emissions from numerous small sources with short stacks is shifted to several tall stacks. Comparison of the three configurations shows that there is little influence from the choice of plant site on the area's air quality (although it would be expected that sulfur dioxide levels would increase in the immediate vicinity of the new facility). It should be noted, however, that increased emissions of sulfur dioxide from utility plants will likely have an impact on air quality at some distance from metropolitan areas, possibly in the form of increased acid precipitation.

The amount of water pollutants generated by the district heating plant is increased as the residential units produce virtually no water pollution. The central plant produces water pollutants as a result of condensing and cleaning operations described earlier. A similar situation occurs with solid wastes since the residential units do not generate any solids. In the cental plant, wastes are generated primarily by flue gas desulfurization systems and particulate control devices. As can be seen from this example, pollutants are being removed from one media, primarily air, in the residential case, and transferred to land and water in the plant case. Not taken into account in this comparison are the indirect environmental impacts that may be reduced from district heating. These include the reduction of fuel oil deliveries, which is virtually eliminated in the section connected to the central heating system. This reduces the pollutant emissions associated with the trips for each delivery as well as the potential spills and emissions during truck and tank filling and transportation. Eliminating residential fuel deliveries also reduces noise impact from fuel trucks.

Waste heat entering the atmosphere is reduced in district heating since much of the heat is recovered for delivery to consumers; however, there are still some impacts on receiving waters since about 15 percent of the waste heat would be discharged in the waste stream. In the residential units, all waste heat is emitted to the atmosphere, which would be eliminated in district heating and could result in microscale climatic changes.

Although the energy conservation values of district heating are becoming more obvious and attractive, a variety of legal constraints in existing energy regulatory programs must be considered before undertaking a district heating project. The principal constraints are those associated with the regulation of the various aspects of the operations of public utilities. The operations of district heating systems will be in the nature of public utility operations since the energy is sold to consumers. This is in contrast to an industrial cogeneration facility which produces energy for internal use. District heating operations will most likely fall under the jurisdiction of various state public utility regulatory agencies. The resolution of the many regulatory requirements by respective commissions need to be resolved to allow the orderly implementation of district heating systems.

In summary, district heating presents opportunities for savings of oil and gas, as well as improving urban air quality. The specific impacts can only be assessed on the basis of site characteristics, fuels used by district heating plants, and the type of fuels displaced.

METHODOLOGY FOR EXPANDING RESULTS TO ESTIMATE NATIONAL ENERGY AND POLLUTANT REDUCTIONS THROUGH COGENERATION

Several recent studies have examined the potential energy savings from cogeneration on a national level as well as by regions and specific industries. Since the amount of pollutants released to the environment is a function of the fuels consumed for producing either electricity or steam, then reducing fuel consumption as a result of increased efficiency through cogeneration will also have some beneficial effect by reducing pollution levels. Accurate estimates of the pollutant reductions can only be determined by the apportioned energy savings by each industry since the types of fuels used and control equipment varies by industry and by region. The following sections describe the methodology that has been developed for estimating both energy and pollutant reductions.

Industrial Energy Savings

Energy savings can potentially be achieved through cogeneration by virtually any industry which requires process steam, although it is usually impractical except for selected plants in an industrial category. Several industries have been identified in previous studies, and have also been described in this report, which have the greatest potential for cogeneration. The following factors need to be analyzed to determine the energy savings potential of the selected industries.

Energy savings potential of representative plant in base year. Each of the selected industries must be divided into respective four digit standard industrial classification (SIC) codes and a representative plant selected for each industry on the basis of size, throughput, or delivered product, whichever is the standard for the industry. Energy savings by the plant is determined by the difference between the increased energy use at the industrial plant, and the reduced energy use at the off-loaded utility plant. As shown by the following relationship:

$$TES = HR_u \times C - F$$

where:

TES = Total Energy Saved (GJoules/year)
HR_u = Heat Rate of Utility (GJoules/kWh)
C = Net Generation by Cogeneration System (kWh/year)
F = Incremental Fuel Consumption by Cogeneration System (GJoules/year)

Having the energy savings from one plant in the SIC code, the emission reduction can be calculated as described previously in the reference plant analyses. This data can be extrapolated to the entire SIC code if the total number of plants in the SIC code is known as well as the average thermal demand compared with the single plant. The

number of plants in the SIC code can be determined from industrial trade associations or from the National Emissions Data System maintained by the EPA Office of Air Quality Planning and Standards. The extrapolation of energy and environmental data from a single plant to the entire industry represents the base year which must then be projected to determine near term (1985) and long term (1990-2000) cogeneration potential.

Projection of cogeneration potential by industry. The potential for cogeneration development in each of the industries is highly dependent upon the growth of the industry itself. Projections for development can be made under two scenarios: (1) cogenerating at existing plants and (2) planning for cogeneration at future plants. The first scenario is usually more difficult to implement due to inadequate excess steam capacity at some plants and inadequate match between required and available steam temperatures and pressure. Of the total number of plants in an industrial category, the ones having a potential for cogeneration can be determined through a screening procedure based on steam requirements, existing fuel use, and boiler age. The base year cogeneration capacity can then be projected to the target years based on historical trends for the industry, planned industrial expansion data from trade associations and industry representatives, and state and Federal government projections. Sources of this information include Census of Manufacturers, County Business Patterns, OBERS Projections, and other Department of Commerce sources.

Pollution Loading Changes Due to Cogeneration

Based on the total energy savings potential of each industry in the country, estimates of pollutant changes can be made if the following factors are known: type of cogeneration system, fuel type, fuel quality and characteristics, and pollution control equipment. Emission factors for fuel burning equipment used in cogeneration systems are found in AP-42, Compilation of Air Pollution Emission Factors. Solid waste and thermal effects are also reduced as a result of decreased fuel usage and the chemical compounds needed for pollutant scrubbing systems.

To determine the emissions that can be saved industry-wide, it is insufficient to base the emissions on the energy saved in the target years. Between the base and target years, certain plants came off-line due to age, increased operating expenses, and reduced capacity factor. These plants, due to their age, will have few emission controls, probably only for particulate emissions. Any new plant coming on stream will be required to have stringent emission controls, usually Best Available Control Technology, due to PSD and non-attainment area regulations. The emissions from the new plants will, therefore, be lower than the displaced plants for an equal amount of energy. Therefore, emissions reduced by cogeneration will have less impact in the long term than in the short term.

SECTION 6

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